

Supplement to Idaho Regional Haze State Implementation Plan for the Second Planning Period



State of Idaho
Department of Environmental Quality



August 2024

Prepared by

Idaho Department of Environmental Quality
Air Quality Division
1410 N. Hilton St.
Boise, ID 83706

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Abbreviations, Acronyms, and Symbols

§	section
CAS	compliance schedule agreement
CEMS	continuous emission monitoring system
CFR	Code of Federal Regulation
DEQ	Idaho Department of Environmental Quality
EPA	United States Environmental Protection Agency
FGD	flue gas desulfurization
km	kilometers
lb/MMBTU	pound per million British thermal units
LNB	Low NO _x Burner
NEI	National Emissions Inventory
NG	natural gas
NH ₃	anhydrous ammonia
NO _x	nitrogen oxides
PM	particulate matter
PM _{2.5}	particulate matter with matter with a diameter of less than 2.5 micrometers
PM ₁₀	particulate matter with a diameter of less than 10 micrometers
ppm	parts per million
PTE	potential to emit
SIP	state implementation plan
SO ₂	sulfur dioxide
SNCR	Selective Noncatalytic Reduction
tpy	ton per year
Q/d	emissions/ distance
ULNB	Ultra Low NO _x Burner
WEP	weighted emissions potential
VOC	volatile organic compounds

Executive Summary

On August 5, 2022, Idaho Department of Environmental Quality (DEQ) submitted the Regional Haze State Implementation Plan (SIP) for the second Planning Period to the United States Environmental Protection Agency (EPA). The August 2022 submittal met the requirements of Section 308 of the Regional Haze Rule (49 CFR 51, Subpart P, § 51.308) for the second planning period (2018–2028) and the progress report requirements for 2014–2018 (40 CFR 51.308(g)(1)-(5)). On August 11, 2022, EPA determined the SIP submittal administratively and technically complete according to 40 CFR 51, Appendix V.

DEQ is submitting this supplement to the August 2022 Regional Haze SIP to address comments, make corrections, and clarify and provide additional information. Table 1 summarizes the information in this supplement and how it impacts the August 2022 submittal.

Table 1. Summary of updates to August 2022 regional haze SIP submittal.

Section of Regional Haze SIP, August 2022	Action
6.1	Update Table 22 with corrected 2017 total emissions and 2017 Q/d for four facilities.
6.1	Replace Table 23 with provided table that corrects Q/d values for 2017.
6.2	Update Table 31 with corrected pollutants selected for each emission unit for Clearwater.
6.3.2	Replace Section 6.3.2 with the included section.
6.3.7	In the second sentence in Section 6.3.7, correct the description of the B&W at TASCOT – Paul to a natural gas boiler instead of dual fired.
6.4	Replace Section 6.4 with the included section.
7.5.1	Replace Section 7.5.1 with the included text.
7.5.2	Replace Section 7.5.2 with the included text.
Appendix B	Update the four-factor analyses and review as follows: • Clearwater Paper: add facility submittal • Itafos: replace the DEQ four-factor analysis review memo; add February 2024 facility submittal for Itafos Conda, LLC. • Amalgamated Sugar Company–Paul: add facility submitted engineering stack tests referenced in four factor analysis.
Appendix D	Correct facility emissions tables.
Appendix E	Replace with reference to Appendix J, that contains all of the redacted permits.
Appendix F	Add Federal Land Managers Consultation Comments and DEQ Responses on this Supplemental.
Appendix G	Add Public Comment Period for Supplement.
Appendix H	Replace with included Appendix H.
New	Add Appendix I. Justification for Not Requiring Controls at Amalgamated Sugar Company LLC – Paul.
New	Add Appendix J. Redacted Permits.

Updates to Section 6 Emissions Control Analysis

The following sections are updated with corrected or new information listed below.

Section 6.1 Point Source Facility Screening and Selection

The 2017 total emissions and 2017 emissions/distance (Q/d) for four facilities were incorrectly calculated and presented in the August 2022 submittal. The correct values are highlighted in yellow below. All other information in Table 22 in the August 2022 submittal remains unchanged.

Table 22. Comparison of Q/d screening with 2014 and 2017 emissions.

Facility	Nearest Class I Area	Distance (km) ^a	2014 Total Emissions (tpy) ^b	2017 Total Emissions (tpy) ^c	2014 Q/d ^d	2017 Q/d ^d
Clearwater Paper Corp – Pulp and Paper and Consumer Products (Clearwater Paper)	Hells Canyon Wilderness	70.9	1506.0	1554	21.3	21.9
Itafos Conda LLC (Itafos)	Grand Teton National Park	104.0	441.2	477.7	4.2	4.6
J.R. Simplot Company – Don Siding Pocatello (Simplot)	Craters of the Moon Wilderness	86.1	1016.2	876.3	11.8	10.2
Northwest Pipeline LLC – Soda Springs (NWP)	Grand Teton National Park	122.2	457.6	579.8	3.8	4.7
P4 Production LLC (TV Facility) (P4)	Grand Teton National Park	111.9	3594.4	2938.4	32.1	26.3
Tamarack Mill, LLC DbA Evergreen Forest and Tamarack Energy Partnership (Tamarack Mills)	Hells Canyon Wilderness	25.5	170.2	69.1	6.7	2.7
The Amalgamated Sugar Company LLC – Nampa (TASCO – Nampa)	Sawtooth Wilderness	114.6	2786.8	590.9	24.3	5.1
The Amalgamated Sugar Company LLC – Paul (TASCO – Paul)	Craters of the Moon Wilderness	78.0	1391.3	577	17.8	7.3
The Amalgamated Sugar Company LLC – Twin Falls (TASCO – Twin Falls)	Jarbridge Wilderness	95.6	2107.0	1420	22.0	14.8
Idaho Forest Group LLC – Riley Creek-Moyie Springs	Cabinet Mountains	44.4	117.0	75.4	2.6	1.7
Plummer Forest Group, Inc – Post Falls	Cabinet Mountains	98.1	228.5	175.2	2.3	1.8
Rexburg Facility of Basic American Foods, a Division of Basic American, Inc.	Yellowstone National Park	63.5	140.0	81.2	2.2	1.3
Boise Air Terminal	Sawtooth Wilderness	90.5	319.6	293.2	3.5	3.2
Northwest Pipeline LLC – Mountain Home	Sawtooth Wilderness	87.7	232.5	202	2.7	2.3

a. Distance in kilometers from the facility to the nearest Class I area boundary

b. Total facility-wide emissions for PM₁₀, NO_x, and SO₂ in 2014.

- c. Total facility-wide emissions for PM₁₀, NO_x, and SO₂ in 2017.
d. Total emissions divided by distance to nearest Class I area boundary.

Table 23 in the August 2022 submittal incorrectly included 2014 data instead of 2017 data.
Replace Table 23 with the following table.

Table 23. Class I areas in Idaho possibly impacted by Idaho facilities using a Q/d threshold of 2.

Class I area	Idaho Facility	2017 Q/d
Craters of the Moon Wilderness	P4 Production, LLC	17.8
	The Amalgamated Sugar Company – Twin Falls	13.2
	J.R. Simplot Company – Don Siding Plant	10.2
	The Amalgamated Sugar Company – Paul	7.4
	Northwest Pipeline – Soda Springs	3.1
	Itafos Conda, LLC	2.9
	The Amalgamated Sugar Company – Nampa	2.5
Sawtooth Wilderness	P4 Production, LLC	9.8
	The Amalgamated Sugar Company – Twin Falls	9.7
	Clearwater Paper Corp – Pulp and Paper Division	5.5
	The Amalgamated Sugar Company – Nampa	5.2
	J.R. Simplot Company – Don Siding Plant	3.9
	Boise Air Terminal	3.5
	The Amalgamated Sugar Company – Paul	3.5
	Northwest Pipeline – Mountain Home	2.3
Selway-Bitterroot Wilderness	Clearwater Paper Corp – Pulp and Paper Division	12.7
	The Amalgamated Sugar Company – Twin Falls	4.1
	J.R. Simplot Company – Don Siding Plant	2.5
	The Amalgamated Sugar Company – Nampa	2.3

Section 6.2 Emission Unit and Pollutant Selection

Table 31 in the August 2022 submittal showed incorrect pollutants for Clearwater Paper emission units. The correct pollutants are highlighted. All other information in Table 31 in the August 2022 submittal remains unchanged.

Table 31. Emission units and pollutants selected for four-factor analysis.

Facility	Emission Unit	Pollutants
Clearwater Paper	No. 4 Power Boiler	NO _x , SO ₂
Clearwater Paper	No. 4 Recovery Furnace	NO _x , PM ₁₀
Clearwater Paper	No. 5 Recovery Furnace	NO _x , PM ₁₀
Itafos	East Sulfuric Acid Plant	SO ₂
NWP-Soda Springs	RICE 4 (TCVA-16)	NO _x
NWP-Soda Springs	RICE 1-3 (TLA-6 Engines)	NO _x
P4	Nodulizing Kiln	PM ₁₀ , SO ₂ , NO _x
Simplot	No. 300 Sulfuric Acid Plant	PM ₁₀ , SO ₂
Simplot	No. 400 Sulfuric Acid Plant	NO _x , SO ₂
Tamarack Mills	Riley Cogeneration Boiler	NO _x , PM ₁₀
TASCO – Nampa	Riley Boiler	PM ₁₀ , SO ₂ , NO _x
TASCO – Paul	B&W Boiler	NO _x
TASCO – Paul	Rentech Boiler	NO _x
TASCO – Paul	North and South Pulp Dryers	PM ₁₀ , SO ₂ , NO _x
TASCO – Twin	Foster Wheeler	PM ₁₀ , SO ₂ , NO _x
TASCO – Twin	B&W Boiler	PM ₁₀ , SO ₂ , NO _x

Section 6.3.2 Itafos Conda, LLC

Replace section 6.3.2 of the August 2022 submittal with the following:

Itafos Conda, LLC operates a phosphate mine and fertilizer plant located in Soda Springs, Idaho. The East Sulfuric Acid Plant was selected to undergo a four-factor analysis to identify potential SO₂ controls.

Itafos initially identified wet flue gas desulfurization, hydrogen peroxide scrubbers, and dry sorbent injection as technically feasible controls for the East Sulfuric Acid Plant. Based on the 2019 Itafos submittal, DEQ determined the three technically feasible controls were cost effective. Itafos then submitted an updated cost-of-compliance analysis that was more representative of their actual operation and present-day costs in 2022. Based on this 2022 updated analysis, the cost effectiveness for all 3 control options exceeded \$6,100 and DEQ determined them not cost effective and therefore not reasonable for the current regional haze implementation period in the August 2022 submittal.

DEQ received comments from the National Park Service during the 2022 public comment period for the August 2022 submittal. After addressing the comments during the preparation of this supplemental, DEQ determined that corrections were needed to the four-factor analysis for

Itafos that resulted in cost effective controls. On August 3, 2023, DEQ notified Itafos that controls would need to be installed based DEQ’s review and evaluation of the public comments. Itafos, after consulting other professionals, determined their previous submittals were significantly flawed and redid their analysis to address the deficiencies. RTP Environmental Associates submitted the final analysis February 29, 2024.

The 2024 submittal addressed site-specific conditions, technical feasibility, and other relevant issues directly pertaining to the Itafos facility and included the following determinations:

- Site-specific physical constraints prohibit the installation of any add-on control equipment in the immediate vicinity to the East Sulfuric Acid Plant stack.
- Dry sorbent injection is not a technically feasible technology due to space constraints mentioned above as well as moisture constraints that would not facilitate the proper reaction to control SO₂ using hydrated lime.
- Previous facility submittals neglected to account for ancillary equipment necessary for wet flue gas desulfurization (FGD) scrubbers control.

Itafos corrected the costs for the two remaining technical feasibility control options resulting in the cost effectiveness shown in Table 31a. The details and final analysis provided by the facility are attached in Appendix B. When analyzing the revised cost effectiveness, DEQ adjusted the interest rate (3.25%) and remaining useful life (30 years) for consistency with other facilities. DEQ has determined that the costs of compliance for the wet FGD scrubber and the hydrogen peroxide scrubber for the East Sulfuric Acid Plant are greater than the \$6,100, and therefore, not reasonable for the current regional haze implementation period (Appendix B).

Table 31a. Control technologies Identified as cost effective for Itafos, Conda LLC.

Control Device	Emission Reduction (tpy)	DEQ adj Cost Effectiveness (\$/ton) ^a	Facility calculated Cost Effectiveness (\$/ton)
Wet flue gas desulfurization ^b	347	\$7,976	10,064

a. DEQ adjusted interest rate 3.25% and remaining useful life (30 years) for consistency.

b. Hydrogen peroxide scrubber is assumed to have similar cost effectiveness, see Appendix B.

Section 6.3.7 Amalgamated Sugar Company—Paul

In the second sentence in section 6.3.7 of the August 2022 SIP, correct the description of the B&W boiler at TASCO – Paul to read natural gas only instead of dual fired.

The TASCO – Paul facility produces refined sugar and animal feed products from sugar beets. The natural gas-fired Rentech and B&W boilers and the north and south pulp dryers were selected for four-factor analysis for NO_x, SO₂, and PM₁₀ (Appendix B).

Section 6.4 Determination of Reasonable Point Source Controls

Replace section 6.4 of the August 2022 submittal with the following section 6.4:

The four-factor analysis process identified three facilities, TASCO – Paul, TASCO – Twin Falls, and TASCO – Nampa with technically feasible control options that have a cost of compliance less than \$6,100 and may be reasonable for the current regional haze implementation period. As stated in sections 6.3.6 and 6.3.8, DEQ determined the following control options meet reasonable progress control requirements for the TASCO – Nampa and TASCO – Twin Falls facilities:

- Remove coal as an allowable fuel for the Riley boiler by June 2027 at the TASCO – Nampa facility.
- Remove coal as an allowable fuel for the B&W boiler at the TASCO – Twin Falls facility.

TASCO also made the following emission reductions, considered above and beyond reasonable progress controls, at their Twin Falls facility:

- Convert the Foster Wheeler boiler from only coal to only natural gas with low-NO_x burner.

The conversion of the Foster Wheeler boiler from coal to natural gas at the Twin Falls facility will reduce emissions of NO_x, PM₁₀, and SO₂ by 775.85 tons per year. The four-factor analysis identified dry FGD for SO₂ and selective non-catalytic reduction (SNCR) for NO_x as cost effective controls, which would have only resulted in 341 tons per year of SO₂ and NO_x (August 2022 submittal, Table 34). The conversion of the Foster Wheeler boiler achieves 434.85 tons per year of NO_x, PM₁₀, and SO₂ more than the best cost-effective controls for that emission unit.

The TASCO – Paul facility cost-effective control options with the greatest emission reductions are eliminating coal for the north and south pulp dryers and ultra-low NO_x burners (ULNB) for the Rentech boiler. Both control options would only reduce 333.48 tons per year of NO_x, PM₁₀, and SO₂ (August 2022 submittal, Table 33).

Overall, the conversion of the Foster Wheeler boiler resulted in 101.42 tons per year of NO_x, PM₁₀, and SO₂ more than the best four-factor analysis identified cost-effective controls at the Paul and Twin Falls facilities combined (August 2022 submittal, Tables 33 and 34).

DEQ determined that no additional controls are required at the TASCO – Paul facility for this planning period due to the fuel conversion of the Foster Wheeler boiler at the Twin Falls facility. Idaho's Class I areas are currently below the adjusted uniform rate of progress needed to achieve the 2064 visibility end goal and are projected to remain below the rate of progress through 2028. Idaho will continue to monitor visibility at its Class I Areas and will evaluate whether additional controls are needed with the next progress report or next implementation period. Appendix I provides additional information.

Based on the information presented above and in Appendices B and I, DEQ determined that the following emission reductions meet the reasonable progress requirements for this implementation period:

- TASCO – Nampa facility: Remove coal as a fuel for the Riley boiler by June 2027 (P-2018.0011 issued February. 15, 2023, Appendix J).

- TASCO – Twin Falls: remove coal as a fuel for the B&W boiler and convert the Foster Wheeler boiler from coal to natural gas (T1-2016.0017 issued November 5, 2021, and T1-2022.0016 issued January 9, 2023, Appendix J).

Table 35 summarizes reasonable progress controls for Idaho. Overall, Idaho facilities will reduce a total of 2,641.25 tons per year of NO_x, PM₁₀, and SO₂ not already accounted for in the RepBase2 or 2028OTBa2 point source EI.

Table 35. Reasonable progress controls for the second implementation period.

Emission Unit	Control Option	Pollutant	PM ₁₀ , NO _x , and SO ₂ Emissions (tpy)		
			Actual	Future	Reduction
TASCO – Nampa					
Riley Boiler	Convert from duel-fired coal/NG to only NG	NO _x	386.04 ^a	255.01 _c	131.03
Riley Boiler	Convert from duel-fired coal/NG to only NG	PM ₁₀	31.86 ^a	7.05 ^c	24.63
Riley Boiler	Convert from duel-fired coal/NG to only NG	SO ₂	1016.4 ^a	0.56 ^c	1015.84
Total emission reductions at TASCO – Nampa (SO ₂ + NO _x + PM ₁₀)					1,171.5
TASCO – Twin Falls					
Foster Wheeler Boiler	Convert from coal fired to NG with LNBS	NO _x	302.59 ^b	59.3 ^d	243.29
Foster Wheeler Boiler	Convert from coal fired to NG with LNBS	PM ₁₀	38.15 ^b	5.5 ^d	32.65
Foster Wheeler Boiler	Convert from coal fired to NG with LNBS	SO ₂	500.4 ^b	0.5 ^d	499.91
B&W Boiler	Convert from duel-fired coal/NG to only NG	NO _x	251.23 ^a	124.84 _c	126.39
B&W Boiler	Convert from duel-fired coal/NG to only NG	PM ₁₀	17.86 ^a	6.78 ^c	11.08
B&W Boiler	Convert from duel-fired coal/NG to only NG	SO ₂	556.97 ^a	0.54 ^c	556.43
Total emission reductions at TASCO – Twin Falls (SO ₂ + NO _x + PM ₁₀)					1,469.75

a. TASCO – Twin Falls and Nampa February 28, 2020, submittal, based on 2014 actual fuel use

b. 2014 NEI v2

c. DEQ analysis of Existing Primary Fuel Replacement Control Option (Appendix B)

d. TASCO – Twin Falls PTC Exemption Concurrence Request on October 26, 2021

Updates to Section 7.5.1 Future Emission Reductions

Replace section 7.5.1 with the following text.

The four statutory factors identified three reasonable progress emission reduction measures, two at the TASCO – Twin Falls facility, and one at the TASCO – Nampa facility, that reduce a total of 2,641.25 tons per year of NO_x, PM₁₀, and SO₂ (section 6.4). Idaho is ensuring these emission reductions are federally enforceable as follows:

TASCO – Twin Falls

- Foster Wheeler Boiler—Switch to natural gas only; T1-2022.0016 issued January 9, 2023; permit condition 4.9.
- B&W Boiler—Remove coal as a fuel; T1-2016.0017, issued on November 5, 2021; permit condition 5.2.

TASCO – Nampa

- Riley Boiler—Remove coal as a fuel no later than July 1, 2027; P-2018.0011 issued February 15, 2023; Permit Condition 4.8.

Table 36 shows the total emission reductions expected to improve visibility during this implementation period. The anticipated changes in visibility are described in section 9.2.

Table 36. Idaho anticipated reduction in emissions (tpy).

Source Category	NH ₃	NO _x	PM ₁₀	PM _{2.5}	SO ₂	VOC
Mobile Source OTB Reductions	-150	-39,884	-1,335	-1,394	-79	-17,715
Point Source OTB Reductions	0	-141	143	65	-455	0
Point Source Reasonable Emission Controls	0	-500	-68	0	-2,072	0
Total	-150	-40,525	-1,260	-1,329	-2,606	-17,715

Updates to Section 7.5.2 Existing Effective Controls

Replace section 7.5.2 with the following text.

The results of the four-factor analysis for several facilities showed that either (1) the emission units currently have existing controls that are considered the most effective and a full four-factor analysis was not completed for the applicable emission unit and pollutant; (2) no new controls were identified for the specific emission unit and pollutant that were technically feasible and cost effective; or (3) no additional controls were needed for reasonable progress due to over control at a nearby facility.

The regional haze program has two main goals: prevent future anthropogenic visibility impairment and remedy any existing anthropogenic visibility impairment. Existing visibility impairment is remedied by reducing emissions from existing sources. Future visibility impairment is prevented by mitigating impacts from new sources and ensuring that existing sources do not increase emissions in a manner inconsistent with reasonable progress.

The existing controls and emission rates for the facilities with no additional controls identified are important to prevent future anthropogenic visibility impairment. These existing controls and current emission rates are federally enforceable through permit conditions. Redacted permits and compliance agreement schedules (CAS) are included in Appendix J.

Federally enforceable emission limits require corresponding performance testing, monitoring, recordkeeping, and reporting conditions. The monitoring and recordkeeping conditions are specific to the emission limit and emission unit. Since all the facilities identified for four-factor analysis are Title V facilities, Idaho's rules for performance testing and reporting for Title V facilities apply. The references to these rules are included for context and are not to be included as an addition to the SIP.

- The "Test Methods and Procedures" (IDAPA. 58.01.01.157) requiring performance testing, applies to all facilities with existing controls.
- The "Standard Contents of Tier I Operating Permits" (IDAPA 58.01.01.322.08 and IDAPA 58.01.01.322.08.11) applies to all facilities with existing effective controls:

Section 7.5.2.1 Clearwater Paper Corp. – Pulp and Paperboard Division

Clearwater Paper has sufficient permit conditions to meet this requirement for the No. 4 Power Boiler and No. 5 Recovery Furnace. Table 37a lists the existing permit conditions that are included in this SIP.

Table 37a. Clearwater Paper permit conditions (T1-2020.0024, issued March 30, 2023).

Permit Condition	Description
5.4	No. 4 Power Boiler SO ₂ Emission Limits
5.5	No. 4 Power Boiler NO _x Emission Limits
5.6	No. 4 Power Boiler NO _x Emission Limits
5.7	No. 4 Power Boiler SO ₂ Emission Limits
5.10–5.15	No. 4 Power Boiler NO _x and SO ₂ Monitoring and Recordkeeping Requirements
7.1	No. 4 and No. 5 Recovery Furnaces PM Emission Limits
7.4	No. 4 and No. 5 Recovery Furnaces alternative PM Emission Limits
7.9	No. 4 and No 5 Recovery Furnaces operation of ESP
7.10	No. 4 and No 5 Recovery Furnaces CMS data quality assurance procedures
8.1	No. 4 Recovery Furnace PM Emission Limits
8.6	No. 4 Recovery Furnace PM Performance Test
9.1	No. 5 Recovery Furnace PM Emission Limits
9.2	No. 5 Recovery Furnace PM Emission Limits
9.6	No. 5 Recovery Furnace NO _x Emission Limits
9.11	No. 5 Recovery Furnace NO _x and PM Monitoring and Recordkeeping Requirements
26.22-26.23	Periodic Compliance Certification

Additionally, DEQ established new conditions in a Permit to Construct for the No. 4 Recovery Furnace shown in Table 37b.

Table 37b. Clearwater Paper permit conditions (P-2023.0035, issued September 28, 2023).

Permit Condition	Description
2.3	No.4 Recovery Furnace NO _x Emissions Limit
2.4	No. 4 Recovery Furnace BLS Firing Rate Limit
2.5	No.4 Recovery Furnace BLS Firing Rate Monitoring
3.10	No.4 Monitoring and Recordkeeping

Section 7.5.2.2 J.R. Simplot Company – Don Siding Plant

J.R. Simplot company has sufficient existing permit conditions to meet this requirement for both No. 300 and No. 400 Sulfuric Acid Plants. Table 38 lists the existing permit conditions included in this SIP.

Table 38. J.R Simplot Company – Don Siding Plant permit conditions (T1-2017.0024, issued March 29, 2023).

Permit Condition	Description
15.9	No. 300 Sulfuric Acid Plant RACT PM ₁₀ Emission Limit – this is already incorporated into Idaho's SIP through the Portneuf Valley PM ₁₀ SIP and therefore not incorporated through Regional Haze.
15.10	SO ₂ limits in the Consent decree
15.11	No. 300 Sulfuric Acid historical SO ₂ limits – this is already incorporated into Idaho's SIP through the Portneuf Valley PM ₁₀ SIP and therefore not incorporated through Regional Haze.
15.19- 15.22	No. 300 Monitoring and Recordkeeping Requirements (CEMS and SO ₂ monitoring)
15.25	Sulfur Dioxide, Sulfuric Acid Mist, and Visible Emissions– this is already incorporated into Idaho's SIP through the Portneuf Valley PM ₁₀ SIP and therefore not incorporated through Regional Haze
15.27	PM ₁₀ Performance testing – this is already incorporated into Idaho's SIP through the Portneuf Valley PM ₁₀ SIP and therefore not incorporated through Regional Haze.
16.6	No. 400 Sulfuric Acid Plant RACT NO _x Emission Limit – this is already incorporated into Idaho's SIP through the Portneuf Valley PM ₁₀ SIP and therefore not incorporated through Regional Haze
16.9	SO ₂ limits in the Consent Decree
16.10	SO ₂ Emission limit – this is already incorporated into Idaho's SIP through the Portneuf Valley PM ₁₀ SIP and therefore not incorporated through Regional Haze.
16.19-16.22	Continuous emission monitoring system (CEMS and SO ₂ monitoring)
16.26	PM ₁₀ and NO _x performance testing – this is already incorporated into Idaho's SIP through the Portneuf Valley PM ₁₀ SIP and therefore not incorporated through Regional Haze.
16.27	SO ₂ and Sulfuric Acid Mist Performance Tests – this is already incorporated into Idaho's SIP through the Portneuf Valley PM ₁₀ SIP and therefore not incorporated through Regional Haze.
18.22-18.23	Periodic Compliance Certification

Section 7.5.2.3 Northwest Pipeline – Soda Springs

The four engines at the Soda Springs location were selected for four-factor analysis for NO_x. No cost-effective controls were found as a result of the analysis. Since the analysis, the company is undergoing a companywide emission reduction effort that will eventually remove the facility from Title V program requirements. For the Soda Springs facility, this effort will include removing all four engines selected for four-factor analysis and replacing them with two turbines. DEQ has entered into a CAS with the facility that outlines the timeline for the removing and replacing these units by 2031. This will result in a 98% reduction in NO_x potential to emit (PTE), from 1,708 tpy to 21 tpy once the existing engines are replaced.

When all CAS requirements are met, DEQ will submit a SIP amendment to remove the CAS from the SIP. This action is appropriate because the emission units selected for four-factor analysis will no longer be in operation.

The CAS includes the following points of agreement:

- Northwest Pipeline – Soda Springs agrees to remove three Clark TLA-6 engines and one Clark TCVA-16 engine and install and operate the following equipment:

- Turbine 1 is a Solar Centaur 40-4700S, 15 parts per million (ppm) NOx unit.
- Turbine 2 is a Solar Taurus 70-10802S, 9 ppm NOx unit.
- The new equipment must be fully operational by July 31, 2031.
- The emission reductions from the equipment upgrades are represented by the following estimates:
 - Total NOx PTE for existing compressor engines:
 - $276.9 \text{ tpy} \times 3 \text{ engines} + 877.23 \times 1 \text{ engine} = 1707.93 \text{ tpy NOx}$
 - Total NOx PTE for the new turbines:
 - $9.72 \text{ tpy NOx} + 11.04 \text{ tpy NOx} = 20.76 \text{ tpy NOx}$
 - Total reduction of NOx PTE when the equipment upgrade project is complete:
 - $1707.93 \text{ tpy NOx} - 20.76 \text{ tpy NOx} = 1687.17 \text{ tpy NOx}$

Section 7.5.2.4 P4 Production LLC

P4 Production has sufficient PM₁₀ and SO₂ existing permit conditions to meet this requirement. Table 39 lists the existing permit conditions included in this SIP.

Table 39. P4 Production LLC (T1-2020.0029, issued December 23, 2021).

Permit Condition	Description
4.2 Table 4.3	PM ₁₀ and SO ₂ emission limits, for kiln stacks only
4.4	Equipment installation
4.5	Throughput limits
4.6	pH limit for scrubbing solution
4.7	Hydro-Sonic Scrubbing System operation for PM emissions
4.19	Operating parameter recordkeeping
4.20	Operations and maintenance manual
4.21	Hydro-sonic scrubber monitoring
13.22-13.23	Periodic Compliance Certification

Additionally, a new emission limit for NOx will be established for the nodulizing kiln. To accomplish this, DEQ entered into a CAS with the facility to allow for a 12-month emission testing plan before establishing appropriate NOx emission limits.

The testing plan consists of stack testing the kiln for NOx over the next 12 months to gather current emission data, compare it with the older data set from 2002–2003, and verify general consistency. The plan will measure NOx emissions monthly over the course of 1 year to provide a more complete look at process variation that includes ambient temperature, kiln feed chemistry, and moisture variation. Measurements will be taken using a 42IQ analyzer that is, calibrated each month using EPA protocol calibration gas used in Method 7E.

A NOx emission limit for the kiln will then be developed based on the average of all sample data plus three sigma and placed into a permit.

The CAS includes the following:

- Detailed timeline for testing, developing, and implementing an emission limit for the nodulizing kiln.
- Agreed upon methods, with associated monitoring and recordkeeping requirements.

When the new emission limit is set according to the schedule outlined in the CAS, DEQ will submit an amendment to the SIP that includes the permit condition with the agreed upon NO_x emission limit for that unit.

Section 7.5.2.5 Tamarack Mill, LLC dba Evergreen Forest and Tamarack Energy Partnership

Tamarack has sufficient existing permit conditions to meet this requirement. Table 40 lists the existing permit conditions that are included in this SIP.

Table 40. Tamarack Mill LLC permit conditions (T1-2019.0024, issued October 17, 2022).

Condition	Description
5.2	Boiler emission limits as it applies to PM ₁₀ and NO _x only
5.3	Fuel-burning equipment PM standard
5.5	Boiler fuel
5.8	Boiler control device requirements
5.17	Boiler and scrubber O&M manual
10.22-10.23	Periodic Compliance Certification

Section 7.5.2.6 Amalgamated Sugar Company – Paul

TASCO – Paul has sufficient existing permit conditions for the Rentech and B&W boiler to meet this requirement. Table 41a lists the existing permit conditions included in this SIP.

Table 41a. The Amalgamated Sugar Company – Paul permit conditions (T1-2019.0020, issued November 5, 2021).

Permit Condition	Description
4.3	NOx emission limit for Rentech boiler (lb/MMBtu)
4.4 (NOx only)	NOx emission limit (tpy) for B&W, Rentech, Nebraska boilers together
4.5	Fuel limitation (NG) for B&W and Rentech boilers
4.6	Boiler operating requirements, only two can operate simultaneously
4.7	Boiler operating limits – total therms for all boilers combined
4.9	Rentech boiler maximum heat input capacity
4.10	Boiler operation recordkeeping as it applies to B&W and Rentech boilers only
4.11	CEMS emission monitoring as it applies to Rentech boiler only
4.12	Recordkeeping as it applies to Rentech boiler only
4.15	Maximum heat input capacity for Rentech boiler
4.16	Rentech boiler performance test and CEMS data reporting requirements
4.18	Emissions reporting requirements as it applies to Rentech boiler only
11.22-11.23	Periodic Compliance Certification

DEQ identified new permit conditions are needed for the north and south pulp dryers. DEQ developed a Permit to Construct to establish PM₁₀, NO_x, and SO₂ emission limits (Table 41b) and associated monitoring and recordkeeping for the north and south pulp dryers.

Table 41b. The Amalgamated Sugar Company – Paul permit conditions (P-2023.0043, issued October 6, 2023).

Permit Condition	Description
2.3, Table 2.2	Emission Limits for the North and South Pulp dryers
2.5	Pulp Dryers Process Production Limits
2.6	Coal Feed Rate Limits
2.8	Control Equipment requirements (cyclones, scrubbers, and FGR)
2.9	Spray- Impingement Scrubber Requirements
2.10-2.12	Monitoring Requirements
3.10	Monitoring and Recordkeeping

Section 7.5.2.7 Itafos Conda LLC

Itafos has sufficient existing permit conditions to meet this requirement. Table 42 lists the existing permit conditions that are included in this SIP.

Table 42. Itafos Conda LLC permit conditions (T1-2016.0015).

Condition	Description
5.1	Sulfur Dioxide Emissions from the East Sulfuric Acid Plant only with respect to T/yr limits in Table 5.3 and footnotes
5.4-5.5	Monitoring and Recordkeeping Requirements
5.11	NSPS 40 CFR 60 Subpart H – Emission Monitoring with CEMS
16.22-16.23	Periodic Compliance Certification

Appendix A. Fire Regime at Idaho's Class I Areas (No Change)

Appendix B. Four-Factor Analyses and Reviews (Append)

1 Clearwater Paper Corp- Pulp and Paperboard Division

Append the Clearwater Four-Factor Analysis Review to include facility justification for fuel oil use.

- Appendix B Clearwater Paper's Response for No. 4 Power Boiler Oil Usage

2 Itafos Conda, LLC

Replace the DEQ Regional Haze Four-Factor Analysis Review Memo for Itafos Conda, LLC with the one included. In addition, add the following Appendix to the Itafos Four Factor Analysis Review.

- Appendix F. Itafos Submittal, February 29, 2024

3 The Amalgamated Sugar Company—Paul

Update the Amalgamated Sugar Company – Paul Four-Factor Analysis Review. Include the following engineering stack tests referenced in TASCO – Paul's submittal in new Appendix D for this review memo:

- November 2002 engineering test for the north and south pulp dryers
- March 2019 engineering test for the north and south pulp dryers

Appendix C. Consultation Dates (No Change)

Appendix D. Emission Unit Selection for Four-factor Analysis and 2015-2020 Emission Inventories (Update)

Correct Appendix D Emission Unit Selection for Four-Factor Analysis and 2015-2020 Emission Inventories

DEQ corrected the following tables in Appendix D. The corrected information is highlighted in yellow in the tables.

- Clearwater Paper Corp – PPD and CPD
 - Corrected the 2014 PM₁₀ emissions for No. 4 and No. 5 recovery boilers due to a formula error.
 - Updated the 2014 total emissions for the No. 4 and No. 5 recovery boilers to account for this correction.
 - Updated the 2014 total PM₁₀ emissions and total (NO_x + PM₁₀ + SO₂) emissions to account for this correction.
- Northwest Pipeline LLC – Soda Springs
 - Corrected the 2014 NO_x, PM₁₀, and SO₂ emissions for three Clark TLA-6 emission units due to a formula error.
 - Updated the 2014 total emission for the three Clark TLA-6 units to account for this correction.
 - Updated the 2014 total PM₁₀, NO_x, and SO₂ emissions and total (NO_x + PM₁₀ + SO₂) emissions to account for this correction.
- Amalgamated Sugar Company LLC – Twin Falls
 - Corrected the 2014 and 2017 PM₁₀ emissions for all emission units due to a formula error.
 - Updated the 2014 and 2017 total emissions for all emission units to account for this correction.
 - Updated the 2014 total PM₁₀ emissions and total (NO_x + PM₁₀ + SO₂) emissions to account for this correction.
- Amalgamated Sugar Company LLC – Paul
 - Included 2014 emissions for the Erie City boiler for complete information.
 - Updated the 2014 total NO_x and SO₂ emissions and total (NO_x + PM₁₀ + SO₂) emissions to account for these corrections.
 - Corrected the 2017 SO₂ emissions for the north pulp dryer to accurately reflect the NEI for consistency.
 - Corrected the 2017 NO_x and SO₂ emissions for the south pulp dryer to accurately reflect the NEI for consistency.
 - Updated the 2014 total emissions for the south and north pulp dryers to account for these corrections.
 - Updated the 2014 total NO_x, PM₁₀, and SO₂ emissions and total (NO_x + PM₁₀ + SO₂) emissions to account for these corrections.
 - Added 2017 table to show actual emissions for completeness.
- Amalgamated Sugar Company LLC – Nampa

Separated 2014 and 2017 emission inventories into two tables for consistency instead of combining 2014 and 2017 emissions into one table.

CLEARWATER PAPER CORP - PPD and CPD - 2014 Emission Inventory

							Four-Factor Analysis	
Emission Unit	NOx (tpy)	PM10 (tpy)	SO2 (tpy)	Total Unit Emissions	% of Facility Total Emissions	Running % of Total Facility Emissions	Yes/No	Pollutants
No 4 Power Boiler	446.00	10.80	34.00	490.80	33%	33%	yes	SO2, NOx
No 5 Recovery Boiler	421.96	36.20	3.53	461.69	31%	63%	yes	NOx, PM10
No 4 Recovery Boiler	169.50	36.82	1.07	207.39	14%	77%	yes	NOx, PM10
No. 5 Recovery Smelt Dissolver	13.35	34.70	2.43	50.48	3%	80%		
No 3 Lime Kiln Stack	34.98	7.97	0.07	43.02	3%	83%		
No 4 Lime Kiln	30.71	6.25	0.02	36.98	2%	86%		
No 2 Power Boiler	31.16	1.02	0.03	32.21	2%	88%		
106 NCG incinerator and NCG venting	13.34	6.26	0.02	19.62	1%	89%		
3L Tissue Machine Hood Exhaust	14.20	2.46	0.09	16.75	1%	90%		
No 1 Power Boiler	14.03	1.39	0.04	15.46	1%	91%		
2L Tissue Machine Hood with dry end, burner and air makeup	11.55	3.81	0.07	15.43	1%	92%		
Pulp and paper roads		12.94		12.94	1%	93%		
Pulp Dryer East & West	8.50	5.06	0.05	13.61	1%	94%		
No 4 Recovery Smelt Dissolver	3.88	6.50	0.71	11.09	1%	95%		
1L Tissue Machine Hood	7.35	3.38	0.04	10.77	1%	96%		
CPD roads		7.75		7.75	1%	96%		
2L Tissue Machine Dust Scrubber Stack		14.24		14.24	1%	97%		
0001 Chlorine dioxide plant (2)	7.22	0.00		7.22	<1%	97%		
Extruder & Space Heating > 5 MM BTU/hr	1.65	4.43	0.01	6.09	<1%	98%		
No. 1 Papermachine Coater Burner	5.05	0.38	0.03	5.46	<1%	98%		
Slaker Scrubber		3.61		3.61	<1%	98%		
Chip Handling (total transfer and pile)		2.62		2.62	<1%	99%		
No. 2 paper machine		4.70		4.70	<1%	99%		
PM Space Heating > 5million BTU/hr	2.25	0.17	0.01	2.43	<1%	99%		
No. 1 Paper Machine		4.21		4.21	<1%	99%		

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1L Tissue Machine Dust Scrubber		2.76		2.76	<1%	100%		
Lime Handling Baghouse		1.38		1.38	<1%	100%		
Sawdust Handling (total transfer and pile)		1.35		1.35	<1%	100%		
Valmet Rewinder Dust Scrubber		1.19		1.19	<1%	100%		
Sawdust transfer cyclone north		1.48		1.48	<1%	100%		
No 2 PM coater burner	0.35	0.03	0.00	0.38	<1%	100%		
Temporary Boilers (2)	0.25	0.05	0.00	0.30	<1%	100%		
Three starch storage silos with baghouses point is center BH		0.17		0.17	<1%	100%		
No. 4 Recovery Salt Cake Day Silo Baghouse		0.14		0.14	<1%	100%		
No. 5 Recovery Saltcake Silo Baghouse		0.14		0.14	<1%	100%		
3L Tissue Machine Dust Scrubber		0.13		0.13	<1%	100%		
Dry Fuel Bin Baghouse		0.00		0.00	<1%	100%		
Totals	1237.27	226.49	42.22					
	Total Emissions (NOx + PM10 + SO2)	1505.99						

NORTHWEST PIPELINE LLC - SODA SPRINGS - 2014 Emission Inventory									
Emission Unit	Unit Type	NOx (tpy)	PM10 (tpy)	SO2 (tpy)	Total Unit Emissions	% of Facility Total Emissions	Running % of Total Facility Emissions	Yes/No	Pollutants
CLARK TCVA-16		406.17	4.76	0.06	410.99	90%	90%	yes	NOx
Clark TLA-6		36.27	0.39	0.00	36.66	8%	98%	yes	NOx
Clark TLA-6		8.12	0.09	0.00	8.21	2%	100%	yes	NOx
Clark TLA-6		1.76	0.02	0.00	1.78	0%	100%	yes	NOx
Boiler		0.26	0.00	0.04	0.30	0%	100%		
Fuel Gas Heater		0.21	0.00	0.03	0.24	0%	100%		
Emergency Generator		0.04	0.00	0.00	0.04	0%	100%		
Totals		452.83	5.26	0.13					
	Total Emissions (NOx + PM10 + SO2)		458.22						

The Amalgamated Sugar Company LLC—Twin Falls 2014 Emission Inventory

								Four-Factor Analysis	
Emission Unit	Unit Type	NOx (tpy)	PM10 (tpy)	SO2 (tpy)	Total Unit Emissions	% of Facility Total Emissions	Running % of Total Facility Emissions	Yes/No	Pollutants
Foster Wheeler Boiler	Boiler	302.59	38.15	500.41	841.14	40%	40%	Yes	NOx, PM10, SO2
B & W Boiler (Dual Fuel)	Boiler	390.33	70.69	556.97	1017.99	48%	88%	Yes	NOx, PM10, SO2
Pulp Dryer - Pulp	Direct-fired Dryer	75.25	92.73	16.82	184.80	9%	97%		
Keeler Boiler (Gas Fired)	Boiler	10.40	0.28	0.02	10.70	1%	98%		
North Belgian Lime Kiln	Kiln	15.30	4.36	0.68	20.34	1%	98%		
Vehicle traffic (paved and unpaved roads) and material handling fugitives	Other fugitive		12.99		12.99	1%	99%		
Sulfur Stove	Other fugitive		0.00	6.87	6.87	0%	99%		
South Belgian Lime Kiln	Kiln	3.83	1.80	0.17	5.80	0%	100%		
Coal unloading and storage	Other process equipment		2.54		2.54	0%	100%		
Granulator System	Other process equipment		2.38		2.38	0%	100%		
Process Slaker	Other process equipment		1.44		1.44	0%	100%		
Totals		797.69	227.36	1081.94					
	Total Emissions (NOx + PM10 + SO2)	2106.99							

The Amalgamated Sugar Company LLC—Twin Falls 2017 Emission Inventory

								Four-Factor Analysis	
Emission Unit	Unit Type	NOx (tpy)	PM10 (tpy)	SO2 (tpy)	Total Unit Emissions	% of Facility Total Emissions	Running % of Total Facility Emissions	Yes/No	Pollutants
Foster Wheeler Boiler	Boiler	333.03	41.85	614.03	988.90	70%	70%	Yes	NOx, PM10, SO2
B & W Boiler (Dual Fuel)	Boiler	190.45	5.16	0.86	196.48	14%	83%	Yes	NOx, PM10, SO2
Pulp Dryer - Pulp	Direct-fired Dryer	77.36	58.84	10.68	146.88	10%	94%		
Keeler Boiler (Gas Fired)	Boiler	34.93	0.95	0.07	35.95	3%	96%		
North Belgian Lime Kiln	Kiln	17.70	3.18	0.79	21.66	2%	98%		
Vehicle traffic (paved and unpaved roads) and material handling fugitives	Other fugitive		11.71		11.71	1%	99%		
Sulfur Stove	Other fugitive		0.00	8.02	8.02	1%	99%		
South Belgian Lime Kiln	Kiln	3.52	1.24	0.16	4.92	0%	100%		
Coal unloading and storage	Other process equipment		2.05		2.05	0%	100%		
Granulator System	Other process equipment		2.08		2.08	0%	100%		
Process Slaker	Other process equipment		1.37		1.37	0%	100%		
Totals		656.99	128.44	634.60					
	Total Emissions (NOx + PM10 + SO2)	1420.03							

The Amalgamated Sugar Company- Paul 2014 Emission Inventory								Four-Factor Analysis	
Emission Unit	Unit Type	NOx (tpy)	PM10 (tpy)	SO2 (tpy)	Total Unit Emissions	% of Facility Total Emissions	Running % of Total Facility Emissions	Yes/No	Pollutants
B & W Boiler	Boiler	356.76	120.15	132.95	609.87	44%	44%	Yes	NOx, PM10, SO2
North Pulp Dryer	Direct-fired Dryer	111.81	69.81	57.55	239.16	17%	61%	Yes	NOx, PM10, SO2
South Pulp Dryer	Direct-fired Dryer	112.76	67.70	49.02	229.48	16%	78%	Yes	NOx, PM10, SO2
ERIE CITY BOILER (Replaced by Rentech Boiler)	Boiler	217.73	2.95	0.47	221.15	16%	93%	No	
Eberhardt Kiln	Kiln	35.18	3.95	0.16	39.28	3%	96%		
Beet Hauling	Open Air Fugitive Source		14.11		14.11	1%	97%		
Material Storage	Open Air Fugitive Source		6.83		6.83	0%	98%		
Sulfur Stove	Other process equipment		0.00	8.13	8.13	1%	98%		
Cooling Tower	Cooling Tower		3.72		3.72	0%	99%		
PELLET COOLER NO. 1	Other process equipment		2.84		2.84	0%	99%		
Pellet Cooler #2	Other process equipment		2.84		2.84	0%	99%		
Pellet Cooler #3	Other process equipment		2.84		2.84	0%	99%		
Drying Granulator	Dryer, unknown		2.51		2.51	0%	99%		
Cooling Granulator #1	Other process equipment		1.57		1.57	0%	100%		
Cooling Granulator #2	Other process equipment		1.57		1.57	0%	100%		
SUGAR HANDLING (bulk load)	Other process equipment		1.17		1.17	0%	100%		
Sugar Handling (process)	Other process equipment		1.13		1.13	0%	100%		
PROCESS/FLUME SLAKER	Other process equipment		0.96		0.96	0%	100%		
Coal and Limerock Unloading	Open Air Fugitive Source		0.89		0.89	0%	100%		
Material Handling	Open Air Fugitive Source		0.45		0.45	0%	100%		
Nebraska Boiler	Boiler	0.34	0.16	0.02	0.52	0%	100%		
Pulp unloading and loadout	Open Air Fugitive Source		0.22		0.22	0%	100%		
Dryer Coal Unloading	Open Air Fugitive Source		0.03		0.03	0%	100%		
					0.00	0%	100%		
Totals		834.58	308.40	248.30					
	Total Emissions (NOx+PM10+ SO2)	1391.28							

THE AMALGAMATED SUGAR COMPANY LLC - PAUL - 2017 Emission Inventory from NEI

								Four-Factor Analysis	
Emission Unit	Unit Type	NOx (tpy)	PM10 (tpy)	SO2 (tpy)	Total Unit Emissions	% of Facility Total Emissions	Running % of Total Facility Emissions	Yes/No	Pollutants
Erie City Boiler (Replaced By Rentech)	Boiler	214.87	5.83	0.46	221.16	31%	31%	No	
B & W Boiler	Boiler	4.62	4.18	0	8.80	1%	33%	Yes	NOx
South Pulp Dryer	Direct-fired Dryer	48.42	69.61	0.10	118.03	17%	49%	Yes	NOx, PM10, SO2
North Pulp Dryer	Direct-fired Dryer	56.84	71.84	0.12	128.85	18%	67%	Yes	NOx, PM10, SO2
Nebraska Boiler	Boiler	1.35	1.22	0.8	2.25	0%	35%		
Drying Granulator	Dryer, unknown		1.88		1.88	0%	35%		
Pellet Cooler No. 1	Other process equipment		1.79		1.79	0%	36%		
Pellet Cooler #2	Other process equipment		1.79	11.2	12.99	2%	38%		
Pellet Cooler #3	Other process equipment		1.79		1.79	0%	38%		
Process/Flume Slaker	Other process equipment		0.95		0.95	0%	38%		
Cooling Granulator #1	Other process equipment		1.17		1.17	0%	38%		
Sulfur Stove	Other process equipment		0.00		0.00	0%	38%		
Cooling Granulator #2	Other process equipment		1.17		1.17	0%	38%		
Sugar Handling (Process)	Other process equipment		1.41		1.41	0%	38%		
SUGAR HANDLING (Bulk Load)	Other process equipment		1.46		1.46	0%	39%		
Material Handling	Open Air Fugitive Source		0.48		0.48	0%	39%		
Material Storage	Open Air Fugitive Source		11.64		11.64	2%	40%		
Beet Hauling	Open Air Fugitive Source		14.79	0.09	14.89	2%	43%		
Cooling Tower	Cooling Tower		4.21		4.21	1%	43%		
Coal And Limerock Unloading	Open Air Fugitive Source		0.88		0.88	0%	43%		
Pulp Unloading And Loadout	Open Air Fugitive Source		0.23		0.23	0%	43%		
Eberhardt Kiln	Kiln	37.09	3.01		40.10	6%	49%		
Temporary Boiler	Boiler		0.03		0.03	0%	49%		
	Totals	363.20	201.38	12.72					
	Total Emissions (NOx + PM10 + SO2)	577.30							

THE AMALGAMATED SUGAR COMPANY LLC - PAUL - 2017 Emission Inventory; PTE for Rentech Boiler

								Four-Factor Analysis	
Emission Unit	Unit Type	NOx (tpy)	PM10 (tpy)	SO2 (tpy)	Total Unit Emissions	% of Facility Total Emissions	Running % of Total Facility Emissions	Yes/No	Pollutants
South Pulp Dryer	Direct-fired Dryer	48.42	69.61	0.10	118.13	27%	27%	Yes	NOx, PM10, SO2
North Pulp Dryer	Direct-fired Dryer	56.84	71.84	0.12	128.81	30%	57%	Yes	NOx, PM10, SO2
Rentech Boiler (replaced Erie City Boiler)	Boiler	68.30	9.80	0.80	78.90	18%	75%	Yes	NOx
Eberhardt Kiln	Kiln	37.09	3.01		40.10	9%	84%		
Beet Hauling	Open Air Fugitive Source		14.79	0.10	14.89	3%	88%		
Pellet Cooler #2	Other process equipment		1.79	11.20	12.99	3%	91%		
Material Storage	Open Air Fugitive Source		11.64		11.64	3%	93%		
B & W Boiler	Boiler	4.62	4.18	0.00	8.80	2%	95%	Yes	NOx
Cooling Tower	Cooling Tower		4.21		4.21	1%	96%		
Nebraska Boiler	Boiler	1.35	1.22	0.80	2.25	1%	97%		
Drying Granulator	Dryer, unknown		1.88		1.88	0%	97%		
PELLET COOLER NO. 1	Other process equipment		1.79		1.79	0%	98%		
Pellet Cooler #3	Other process equipment		1.79		1.79	0%	98%		
SUGAR HANDLING (bulk load)	Other process equipment		1.46		1.46	0%	98%		
Sugar Handling (process)	Other process equipment		1.41		1.41	0%	99%		
Cooling Granulator #1	Other process equipment		1.17		1.17	0%	99%		
Cooling Granulator #2	Other process equipment		1.17		1.17	0%	99%		
PROCESS/FLUME SLAKER	Other process equipment		0.95		0.95	0%	99%		
Coal and Limerock Unloading	Open Air Fugitive Source		0.88		0.88	0%	100%		
Material Handling	Open Air Fugitive Source		0.48		0.48	0%	100%		
Pulp unloading and loadout	Open Air Fugitive Source		0.23		0.23	0%	100%		
Temporary Boiler	Boiler		0.03		0.03	0%	100%		

Supplement to Idaho Regional Haze State Implementation Plan									
Sulfur Stove	Other process equipment		0.00		0.00		0%		100%
	Totals	216.62	205.35	13.12					
	Total Emissions (NOx + PM10 + SO2)	435.09							
THE AMALGAMATED SUGAR COMPANY LLC - NAMPA - 2014 Emission Inventory									

								Four-Factor Analysis	
Emission Unit	Unit Type	NOx (tpy)	PM10 (tpy)	SO2 (tpy)	Total Unit Emissions	% of Facility Total Emissions	Running % of Total Facility Emissions	Yes/No	Pollutants
Riley Boiler	Boiler	676.29	104.29	1016.41	1796.99	64%	64%	Yes	NOx, PM10, SO2
B&W Boiler #2	Boiler	144.76	28.71	282.81	456.28	16%	81%	No	
B&W Boiler #1	Boiler	141.52	27.60	278.24	447.36	16%	97%	No	
Main Mill	Roof vents/Building vents	31.15	0.00	0.10	31.25	1%	98%		
Union Boiler (gas)	Boiler	11.32	6.36	0.07	17.75	1%	99%		
Lime Kiln B	Calciner	5.59	0.47	0.14	6.20	0%	99%		
Drying Granulator	Other bulk material equipment		6.01		6.01	0%	99%		
Thin Juice Sulfur Stove	Other process equipment		0.00	5.80	5.80	0%	99%		
Lime Kiln A	Calciner	4.80	0.40	0.12	5.32	0%	100%		
Facility Fugitives - Raw Beets	Other fugitive		5.30		5.30	0%	100%		
Standard Liquor Sulfur Stove	Other process equipment		0.00	2.26	2.26	0%	100%		
A&B Process Slakers	Chemical Reactor		1.57		1.57	0%	100%		
Cooling Granulator #1	Other bulk material equipment		1.11		1.11	0%	100%		
Cooling Granulator #2	Other bulk material equipment		1.11		1.11	0%	100%		
Pellet Mill Cooler Baghouse	Screen		1.11		1.11	0%	100%		
Lime Kiln Building Material Handling	Roof vents/Building vents		0.49		0.49	0%	100%		
Sugar Handling (Process #2)	Other bulk material equipment		0.46		0.46	0%	100%		
Sugar Handling (Specialties)	Other bulk material equipment		0.28		0.28	0%	100%		
Sugar Handling (Retail Packaging)	Other bulk material equipment		0.20		0.20	0%	100%		
	Totals	1015.42	185.46	1585.95					
	Total Emissions (NOx + PM10 + SO2)	2786.83							

THE AMALGAMATED SUGAR COMPANY LLC – NAMPA—2017 Emission Inventory

								Four-Factor Analysis	
Emission Unit	Unit Type	NOx (tpy)	PM10 (tpy)	SO2 (tpy)	Total Unit Emissions	% of Facility Total Emissions	Running % of Total Facility Emissions	Yes/No	Pollutants
Riley Boiler	Boiler	347.91	26.85	0.74	375.50	64%	64%	Yes	NOx, PM10, SO2
B&W Boiler #1	Boiler	61.04	4.72	0.13	65.89	11%	75%		
B&W Boiler #2	Boiler	60.48	4.68	0.13	65.29	11%	86%		
Main Mill	Roof vents/Building vents	36.01	0.00	0.75	36.75	6%	92%		
Union Boiler (gas)	Boiler	11.95	2.58	0.07	14.60	2%	94%		
Lime Kiln B	Calciner	6.08	0.39	0.13	6.60	1%	96%		
Facility Fugitives - Raw Beets	Other fugitive		6.46		6.46	1%	97%		
Lime Kiln A	Calciner	5.92	0.38	0.12	6.42	1%	98%		
Drying Granulator	Other bulk material equipment		4.55		4.55	1%	98%		
Standard Liquor Sulfur Stove	Other process equipment		0.00	1.76	1.76	0%	99%		
A&B Process Slakers	Chemical Reactor		1.70		1.70	0%	99%		
Thin Juice Sulfur Stove	Other process equipment		0.00	1.34	1.34	0%	99%		
Cooling Granulator #1	Other bulk material equipment		0.84		0.84	0%	99%		
Cooling Granulator #2	Other bulk material equipment		0.84		0.84	0%	100%		
Pellet Mill Cooler Baghouse	Screen		0.83		0.83	0%	100%		
Lime Kiln Building Material Handling	Roof vents/Building vents		0.57		0.57	0%	100%		
Sugar Handling (Process #2)	Other bulk material equipment		0.52		0.52	0%	100%		
Sugar Handling (Specialties)	Other bulk material equipment		0.28		0.28	0%	100%		
Sugar Handling (Retail Packaging)	Other bulk material equipment		0.23		0.23	0%	100%		
	Totals	529.39	56.43	5.17					
Total Emissions (NOx + PM10 + SO2)			590.99						

Appendix E. Amalgamated Sugar Company – Twin Falls Tier I Permit (T1-2016-0017) (Replace)

Remove Redacted Permit and replace with the following line:

See Appendix J for Amalgamated Sugar Company – Twin Falls Tier I Permit (T1-2016-0017).

Appendix F. Federal Land Managers Consultation Comments and DEQ Responses (Append)

The following table is appended to Appendix F.

FLM Consultation Comments and DEQ Comments on Supplement

Number	Comment	DEQ Response
National Park Service (NPS) 1. Itafos Conda	This facility is an important contributor to regional haze in NPS Class I areas. As we shared in March 2022 comments, the Western Regional Air Partnership weighted emissions potential analysis ranks the Itafos facility as the sixth largest contributor to ammonium sulfate visibility impairment at Yellowstone and Grand Teton National Parks. In July 2022 comments on the public draft SIP the NPS recommended that a wet packed scrubber would likely be cost-effective to reduce SO₂ emissions from the East Sulfuric Acid Plant. We appreciate Idaho DEQ's consideration of our comments and the updated information provided in Appendix B of the draft SIP supplement. These include a new facility four-factor analysis and DEQ's review of the analysis. In its review, Idaho DEQ provided an adjusted cost effectiveness for wet flue gas desulfurization or hydrogen peroxide scrubbing of about \$8,000/ton SO₂ removed (Table 5). Although this cost is higher than Idaho DEQ's threshold of \$6,100/ton SO₂, it is within the range of cost-effectiveness thresholds considered reasonable by other states. For example, Colorado, Nevada, New Mexico, and Oregon chose cost-effectiveness thresholds as high as \$10,000/ton for this round of regional haze planning. Given the impact of emissions from this facility on NPS Class I areas, the NPS recommends Idaho DEQ consider requiring installation of an SO₂ scrubbing system in this planning period.	Neither the Regional Haze Rule nor guidance requires states to establish a specific cost threshold in determining reasonable progress. Each state is unique and has different contributing factors in determining what is considered reasonable for each planning period. It is inappropriate to assume what is considered a reasonable cost threshold in one state would be reasonable in another state. DEQ responded to a similar comment from the National Parks Service: <i>"For transparency and fairness, Idaho elected to base the cost threshold on prior BART decisions made in the first regional haze implementation period. Idaho used the Consumer Price Index (CPI) inflation calculator to escalate a \$5,000 cost threshold from January 2010 to April 2021.</i> <i>Idaho's cost threshold allows enough latitude in determining reasonable controls for a complex mix of emission units selected for the four-factor analysis. The threshold neither removes from consideration all technically feasible controls nor automatically considers all controls cost-effective. No changes were made based on this comment."</i>
NPS 2. TASCO-Paul	The NPS previously recommended removing coal as a fuel for the pulp dryers at this facility to further reduce SO₂ and NO_x emissions. In the draft SIP supplement, Idaho DEQ found that eliminating coal for the north and south pulp dryers is the most cost-effective control option with the greatest emission reductions for the Paul facility. However, no additional controls are required at the facility for this planning period due to the fuel conversion of the Foster-Wheeler boiler at the Twin Falls facility (Section 6.4, p. 5). The NPS disagrees with using emissions reductions at one facility to justify dismissal of cost-effective controls at another facility. The NPS continues to recommend the removal of coal as a fuel for the pulp dryers at the TASCO Paul facility to reduce haze causing emissions in this planning period.	Idaho disagrees that additional controls at the TASCO—Paul facility are needed to meet reasonable progress. The Amalgamated Sugar Company made significant reductions above and beyond what is required for this implementation period. The Paul and Twin Falls facilities are in close proximity and the total emissions that were reduced at the TASCO-Twin Falls facility are greater than the maximum potential annual emission reductions if the best cost-effective controls identified in the original were installed at both facilities.

NPS 3. TASCO— Twin Falls	The NPS appreciates the removal of coal as an allowable fuel for the B&W boiler in 2021 and the conversion of the Foster-Wheeler boiler to natural gas only with a low-NOx burner in 2027. We have no further comments on this facility at this time.	No comment
NPS 4. J.R. Simplot— Don Siding Pocatello	The NPS previously recommended that a wet packed-tower scrubber may be cost effective for the J.R. Simplot sulfuric acid plants No. 300 and No. 400. The NPS also recommended that Idaho DEQ include an SO ₂ analysis for the sulfuric acid plants in the SIP. In the draft SIP supplement, Idaho DEQ concluded that the existing permit conditions for both sulfuric acid plants are sufficient to demonstrate that the existing controls are effective and that a four-factor analysis and additional SO ₂ controls are not needed for this planning period. The NPS continues to recommend that a wet packed-tower scrubber is likely cost-effective relative to Idaho DEQ's cost threshold and should be evaluated in the SIP.	When EPA issued the Consent Decree to JR Simplot in 2015, the emission limits for the #300 and #400 Sulfuric Acid Plants were considered "BACT equivalent." The emission limits included in the consent decree were consistent with other emission limits for existing facilities listed in the RACT/BACT/LEAR Clearinghouse (RBLIC) for similar emission units at the time the consent decree was finalized. Idaho DEQ continues to find the existing permit conditions for both sulfuric acid plants are sufficient to demonstrate that the existing controls are effective and that a four-factor analysis and additional SO ₂ controls are not needed for this planning period.
NPS 5. Northwest Pipeline— Soda Springs	The draft SIP supplement includes a new compliance agreement schedule requiring the facility to replace its four natural gas-fired lean-burn reciprocating internal combustion engines (RICE) with two gas-fired turbines by July 2031. This will result in a 98% reduction in NO_x potential to emit (PTE), from 1,708 tons/year to 21 tons/year once the existing engines are replaced. The language in Section 7.5.2.3 of the draft SIP supplement lists the PTE of the existing engines and does not explain this clearly. The NPS recommends updating this section to show the expected change in emissions. The anticipated reduction in NO_x emissions from this facility is significant and will help improve visibility in Class I areas. The NPS recommends that this replacement take place before the end of the current planning period.	DEQ appreciates NPS's comments and clarifying language has been added to demonstrate the reductions in PTE at this facility because of the change in these units. The proposed changes at Northwest Pipeline – Soda Springs are being made companywide across the region, not solely at this facility. EPA has proposed approval of Oregon DEQ's Supplement to the 2018-2028 Regional Haze Plan which has similar initiatives at the Northwest Pipeline – Oregon City facility with installation occurring by 2031. DEQ has required the replacement of the Engines by 2031 to remain consistent with the company's efforts. Section 169A(b)(2)(B) of the Clean Air Act requires "a long term (ten to fifteen years) strategy for making reasonable progress" toward national regional haze goals. 40 CFR 51.308(f) set the 2018-2028 planning timeline for Round 2 of Regional Haze. However, EPA regulations explicitly contemplate the installation of controls outside of the planning period. 40 CFR 51.308(f)(2)(i) states that "[i]n considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress." This demonstrates that the State may require control measures that cannot reasonably be installed within the planning period.
	Previous NPS comments provided several recommendations to improve the cost analysis for adding selective catalytic reduction (SCR) to	Neither the Regional Haze Rule nor guidance requires states to establish a specific cost threshold in determining reasonable progress.

NPS 6. Clearwater Paper	control NOx emissions from the No. 4 power boiler. The four-factor analysis used an obsolete version of the Control Cost Manual (CCM) and a vendor quote from another facility that was 20 years old. The analysis also used substantial contingency costs and unsupported retrofit factors. The NPS recommended using the default CCM and contingency costs in the absence of a robust justification for increased retrofit factors and contingency costs. In the response to comments provided with the draft SIP supplement, Idaho DEQ states that the analysis was re-run by the consultant and the costs were above \$20,000/ton of NOx removed. Idaho DEQ also evaluated the effect of contingency costs on the cost effectiveness by eliminating contingency costs entirely and found SCR costs to be still above its cost threshold. Updated NPS application of the current CCM SCR methodology finds cost effectiveness ranging from \$3,100–\$17,500/ton depending upon the fuel, the cost year (represented by the Chemical Engineering Plant Cost Index), and the interest rate. (See attached cost factor table and workbooks.) The firing of wood (approximated by selecting the "lignite" fuel option in the CCM workbook) drives costs into the upper end of the range at \$17,510/ton of NOx removed. Still, this cost effectiveness is below the value considered reasonable for paper mill boilers by EPA in its Good Neighbor Plan (GNP). In the GNP, EPA estimated average NOx control costs at paper mills at \$14,134/ton in 2016\$ (Table V.C.2–3, 88 FR 36740), which is equivalent to \$20,819 in 2023\$. Although the estimated cost of SCR is above Idaho's cost-effectiveness threshold, and Idaho is not subject to GNP, the RHR 2019 guidance recommends states consider costs that are reasonable in other Clean Air Act (CAA) programs when evaluating whether a cost is reasonable under the RHR: <i>When the cost/ton of a possible measure is within the range of the cost/ton values that have been incurred multiple times by sources of similar type to meet regional haze requirements or any other CAA requirement, this weighs in favor of concluding that the cost of compliance is not an obstacle to the measure being considered necessary to make reasonable progress.</i> (Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, Section II (B)5, P. 40) Based on this, the NPS recommends that Idaho DEQ consider whether it would also be reasonable to require SCR to control NOx emissions from the Clearwater No. 4 power boiler.	Each state is unique and has different contributing factors in determining what is considered reasonable for each planning period. It is inappropriate to assume what is considered a reasonable cost threshold in one state would be reasonable in another state. DEQ responded to a similar comment from the National Parks Service : <i>"For transparency and fairness, Idaho elected to base the cost threshold on prior BART decisions made in the first regional haze implementation period. Idaho used the Consumer Price Index (CPI) inflation calculator to escalate a \$5,000 cost threshold from January 2010 to April 2021.</i> <i>Idaho's cost threshold allows enough latitude in determining reasonable controls for a complex mix of emission units selected for the four-factor analysis. The threshold neither removes from consideration all technically feasible controls nor automatically considers all controls cost-effective. No changes were made based on this comment."</i>
	In Appendix B to the draft SIP supplement, Clearwater justifies continuing to use high-sulfur	DEQ requested and Clearwater Paper provided a justification for not evaluating control options

	fuel oil as an alternative fuel in the No. 4 power boiler. The justification states that the annual limit of 100 ton/year of SO₂ is sufficient to ensure that fuel oil will be restricted to approximately 4–5% of the annual MMBtu consumption. However, visibility impairment is a short-term air quality related value and is sensitive to short-term changes in emissions. The NPS continues to recommend that Idaho DEQ require use of low-sulfur fuel oil as an alternative fuel in the No. 4 power boiler.	for fuel oil use in the No. 4 Power Boiler. Clearwater described that fuel oil can only supply a small fraction of the MMBtu needed to run the facility. Fuel oil emissions are inherently limited by existing NO_x and SO₂ limits (T1-2020.0024). To meet these emission limits and operational requirements, fuel oil is restricted to approximately 4%–5% of the annual MMBtu consumption. Because of this, wood or natural gas must be used as the primary fuel to allow mill operation. DEQ determined that it is not reasonable to require a four- factor analysis of low-sulfur fuel oil due to the limited use of fuel oil.
	The NPS also commented previously on the analysis of the recovery furnaces, suggesting that Clearwater evaluate the use of a quaternary air system to reduce NO_x emissions from the recovery boilers. In the draft SIP supplement response to comments, Idaho DEQ provided additional information on NO_x emissions testing on the No. 5 recovery boiler. Based on this information, the NPS agrees that application of quaternary air to the recovery furnaces would not yield significant reduction in NO_x emissions.	DEQ appreciates NPS's concurrence that application of quaternary air to the recovery furnaces would not yield significant reduction in NO_x emissions.
NPS 7. Appendix J	The NPS supports the addition of facility permits to the SIP supplement. However, it is not clear why the permits, which appear to be current, are redacted. We recommend Idaho DEQ include the unredacted permits in the SIP for transparency.	DEQ appreciates NPS comments, the complete issued Tier I Operating Permits and Permits to Construct are available on our website https://www.deq.idaho.gov/permits/issued-permits-and-water-quality-certifications/.

Appendix G. Public Comment Period (Append)

Add Public Comment Period for Supplement

Appendix H. DEQ Responses to Public Comments (Replace)

Replace Appendix H with this Section.

1 2022 SIP Submittal Response to Public Comments

1.1 EPA comments

Comment #	Comment	DEQ Response
1	Existing Effective Controls: Idaho determined that no additional controls were feasible at six of the sources. See Section 6.3. However, Idaho did not definitively determine whether the existing controls were necessary for reasonable progress. Nor did Idaho submit enforceable emissions limitations reflecting existing controls for these sources. If Idaho determines that no additional (i.e., new) measures are necessary to make reasonable progress for a particular source, then Idaho must then determine whether the source's existing measures are necessary to make reasonable progress. See section 4 (pages 8 – 12) of the Clarifications Memorandum for information on determining when a source's existing measures are necessary to make reasonable progress. Generally, a source's existing measures are needed to prevent future emission increases and are thus needed to make reasonable progress. If Idaho concludes that the existing controls at a selected source are necessary to make reasonable progress, Idaho must adopt emissions limits based on those controls as part of its long-term strategy for the second planning period and include those limits in its SIP (to the extent they do not already exist in the SIP). Alternatively, if Idaho can demonstrate that a source will continue to implement its existing measures and will not increase its emission rate, it may be reasonable to conclude that the existing controls are not necessary to make reasonable progress. Such a demonstration should be supported by documentation, such as the data and analysis described in the Clarifications Memorandum. In such case, the emission limits may not need to be adopted into the long-term strategy and SIP. We recommend that Idaho clearly state in its determination for each source whether it is including either existing limits for each source in the long-term strategy and SIP or whether emission limits already exist in the SIP. See Guidance at 43; Clarifications Memorandum at 8-9.	No technically feasible and/or cost-effective controls were identified for six of the nine facilities selected for four-factor analysis. DEQ is submitting the permit conditions for existing controls for the five facilities. See Section 7.5.2 and new Appendix J of the regional haze supplement.
2	Four-Factor Analyses Characterizing the Cost of Compliance (Cost Effectiveness Calculations): The EPA has not reviewed the revised cost calculations in the Idaho Regional Haze Plan for 2018 through 2028, posted for public comment on June 22, 2022, but is reiterating the recommendation from our December 23, 2021, comment letter that Idaho make any necessary revisions of its cost-effectiveness calculations to conform to EPA's guidance, namely the Air Pollution Control Cost Manual.	DEQ air quality engineers reviewed each facility's four-factor analysis submittals to ensure they followed the EPA cost control manual or provided sufficient justification for their approach. DEQ worked with facilities to use site-specific information when available. When facilities did not use EPA recommended values for interest rate and equipment life, DEQ adjusted the submitted cost analysis to recalculate the cost-effectiveness using the EPA recommended values.

		These adjusted values, included in Appendix B where applicable, did not change the reasonable progress controls decision.
3	Adopting Additional Controls Determined to be Cost Effective into the Long-Term Strategy and SIP: In Section 6.4 of the SIP, Idaho determines that no controls are necessary for the TASCO Paul facility because controls at the nearby TASCO Twin Falls facility reduce emissions impacting the same Class I area. However, there are a potential cost effective SO ₂ and NO _x controls for TASCO Paul. The EPA recommends including enforceable emission limits associated with the additional controls on the TASCO Paul facility Idaho determined are cost effective.	Idaho disagrees that additional controls at the TASCO–Paul facility are needed to meet reasonable progress. DEQ provided additional justification for this decision in Section 6.4 and Appendix I of the regional haze supplement.
4	Practical Enforceability of Controls: Please include in the plan each existing and new control requirement necessary for reasonable progress in a form that is enforceable as a practical matter. This includes any on-the-way measure. The plan should include for each source and unit: 1) the regulation, permit, order, or other enforceable mechanism that requires compliance with the prescribed control requirement and/or emission limit; 2) the monitoring, recordkeeping, and reporting requirements necessary to determine compliance; and 3) the effective date of the control requirement and any applicable compliance schedule.	Applicable permit conditions or compliance agreement schedules for all existing and additional controls are included in Sections 7.5.1, 7.5.2 and Appendix J of the regional haze supplement.

1.2 National Park Service Comments

Comment #	Comment	DEQ Response
Executive Summary		
1	IDEQ was responsive to NPS consultation comments by (1) including the NPS requested emission unit information in Appendix D, (2) adjusting some of the control costs analyses, and (3) by requiring a fuel switch from coal to natural gas for the Riley Boiler at the TASCO Nampa facility. In this enclosure, the NPS reiterates several remaining recommendations that could further reduce haze causing emissions, which were previously provided during the FLM consultation period. In summary, the NPS recommends: • IDEQ include an evaluation of quaternary air as a NO_x control option for the recovery furnaces at the Clearwater Paper facility in the SIP. • IDEQ require wet packed tower scrubbers to reduce SO₂ emissions from the Itafos Conda east sulfuric acid plant and J.R. Simplot -Don Siding Pocatello sulfuric acid plants No. 300 and No. 400. The NPS revised analyses indicate this control option is still cost-effective for these units/facilities. • IDEQ require SCR to reduce NO_x emissions from the B&W and Foster Wheeler Boilers at the TASCO Twin Falls facility. NPS analyses indicate that SCR is cost-effective even when combusting natural gas in these units and could remove approximately 400 additional tons of NO_x per year from this facility.	These comments are addressed under the facility-specific comments below. • Clearwater Paper–Comment • J.R. Simplot–Comment • TASCO–Twin Falls: Comment • TASCO–Nampa: Comment • TASCO–Paul: Comment

Comment #	Comment	DEQ Response
	• IDEQ considered the installation of SCR on the Riley Boiler at the TASCO Nampa facility in the SIP. NPS analyses show that additional NO_x control with SCR for the Riley Boiler is below IDEQ's cost threshold at \$2,826/ton even when combusting 100% natural gas. • IDEQ remove coal as a fuel for the pulp dryers at the TASCO Paul facility to further reduce SO₂ and NO_x emissions or install SCR. (If coal is combusted, SCR may be economically feasible.) The NPS recommends that the final determinations for the Paul facility are based on the four statutory factors for individual units at the facility and not reductions occurring at other Idaho facilities.	
2	Cost Thresholds: IDEQ's cost-effectiveness threshold was derived by escalating the cost/ton threshold identified in the first round of regional haze planning for Best Available Retrofit Technology (BART) determinations to 2019\$ using the Consumer Price Index (CPI). The NPS agrees that inflation will necessitate an increase in cost thresholds year-over-year. Without periodic adjustments the likelihood of implementing future controls will diminish over time. The NPS notes that the EPA Control Cost Manual (CCM) advises against using the CPI for price escalations associated with control technology cost assessments. However, as noted in the facility-specific comments below, the NPS revised our initial cost estimates to reflect recent inflation and interest rate hikes that have occurred since 2019. The NPS made these revisions to be consistent with CCM recommendations, which utilizes the "overnight" estimation method when calculating capital costs. The NPS recommends that a commensurate adjustment to the cost-effectiveness threshold will be necessary if the 2021\$ control cost estimates are used. If the CEPCI is used to adjust for inflation between the BART time period and to 2021, this results in a cost-effectiveness threshold of approximately \$7500/ton to \$8000/ton depending on the escalation period. Based on the revised NPS cost analyses (2021\$), most of the controls recommended by the NPS are still below Idaho's cost threshold of \$6,100/ton and all the controls are below the escalated threshold of \$7,500-\$8,000/ton (see specific facility write-ups below). The NPS recommends that these controls are implemented in this round of regional haze planning. Additionally, reasonable progress (RP) determinations are distinct from BART determinations and cost thresholds for RP determinations will need to be higher than those established for BART to achieve the ultimate visibility goal of no human-caused impairment. EPA echoed this concept in their response to comments on their final approval of Arizona's Regional Haze and Interstate Visibility Transport Federal	Idaho used the Consumer Price Index (CPI) inflation calculator to escalate a \$5,000 cost threshold from January 2010 to April 2021. Neither the Regional Haze Rule nor guidance requires states to establish a specific cost threshold in determining reasonable progress. For transparency and fairness, Idaho elected to base the cost threshold on prior BART decisions made in the first regional haze implementation period. The threshold is not a direct comparison to capital project spending or industrial goods, so its validity is not tied to a specific escalation index. Idaho's cost threshold allows enough latitude in determining reasonable controls for a complex mix of emission units selected for the four-factor analysis. The threshold neither removes from consideration all technically feasible controls nor automatically considers all controls cost-effective. No changes were made based on this comment.

Comment #	Comment	DEQ Response
	Implementation Plan. As emissions decline, smaller reductions from a greater number of sources will be necessary and these reductions will come at a higher cost. This necessitates an increase in cost-effectiveness thresholds beyond accounting for inflation alone. Many other states have identified a cost-effectiveness threshold in their draft proposals in this round of regional haze planning, with three states, Nevada, Colorado, and Oregon, selecting a cost-effectiveness threshold of \$10,000/ton. The \$10,000/ton thresholds selected by other states adequately addresses this issue.	
3	Consideration of the URP in RP determinations: IDEQ is basing the control determination for the Paul facility on the determination made for the Twin Falls facility rather than the four statutory factors. It appears that IDEQ has qualified this conclusion by noting that the Idaho Class I areas will be below the uniform rate of progress (URP) by the end of the planning period. The NPS notes that visibility benefit and visibility projections relative to the URP alone are not an appropriate basis for rejecting otherwise cost-effective controls. EPA covered this topic in their July 8, 2021, Clarification Memo (§5.4). NPS recommends that this qualifying statement be removed from the SIP language and that the determination for the Paul facility be based on the four statutory factors.	Idaho is not relying on the uniform rate of progress (URP) as a safe harbor. Idaho is considering visibility impacts in its control determination. EPA interpreted the CAA and RHR as allowing states to consider visibility alongside the four statutory factors when determining the emission reduction measures that are necessary to make reasonable progress (July 2021 clarification memo). To clarify Idaho's decision and provide additional justification for not requiring additional controls at the TASCO–Paul facility, Section 6.4 was updated, and Appendix I was added in the regional haze supplement.
4	Appendix D Emission Unit selection for 4FA and 2015-2020 Emission Inventories: Thank you for providing additional information regarding emission unit selection at the individual facilities and documenting the rationale for unit selection in the SIP. The additional information provided in Appendix D is clear, concise and supports the basis for Idaho Department of Environmental Quality's (IDEQ) source and pollutant selection process.	No changes were made to the SIP based on this comment.
5	Four-Factor Analysis Assumptions—Interest Rate, Equipment Life and CEPCI Values: In the SIP Appendix B, IDEQ notes: Where possible, DEQ recalculated the cost of compliance for control technologies using an equipment life of 30 years and a bank prime rate of 3.25% based on feedback from EPA. NPS appreciates IDEQ's response to NPS input on these issues and acknowledges that since the FLM review draft SIP was released, the bank prime rate increased to 4.75% on June 16, 2022, and the CEPCI value used to escalate costs based on annual inflation increased to 708.0 in 2021. Any revisions made to NPS estimates reflect these recent changes. Additionally, several revisions were made to NPS cost analyses based on IDEQ's response to comments (i.e., increased reagent costs). We have noted where these parameters influenced the outcome of NPS cost-effectiveness recommendations. Per our comments in Section	Facilities submitted the four-factor analyses in late 2019 to early 2020 (November 26, 2019, through February 14, 2020). A higher interest rate and accounting for inflation will increase the cost per ton of each control option. Facilities with no cost-effective controls at the lower interest and not accounting for inflation do not need to redo their analysis. It is unreasonable to update the cost threshold for inflation after the analyses are complete because DEQ made preliminary decisions based on those initial cost thresholds. No changes were made to the SIP based on this comment.

Comment #	Comment	DEQ Response
	2.3, we recommend that the cost thresholds should also be adjusted for inflation.	
Section 3.1 Clearwater Paper Corporation		
6	In Appendix B, IDEQ notes that “Clearwater did not provide a cost assessment for combusting only low sulfur fuel oil in the No. 4 Power Boiler, but historically (for at least the last 10 years) Clearwater has only combusted low sulfur wood and natural gas in the No. 4 Power Boiler. Higher sulfur content fuel oil has not been combusted in the recent past, and DEQ concentrated its review on fuels that are actually used (i.e., wood and natural gas).” Please clarify whether this assumption is enforceable through the permit. The NPS recommends that assumptions used to forgo and/or limit the scope of control technology analyses be reflected in the permit. This is consistent with EPA guidance provided in the July 2021 Clarification Memo.	DEQ requested and Clearwater Paper provided a justification for not evaluating control options for fuel oil use in the No. 4 Power Boiler. Clearwater described that fuel oil can only supply a small fraction of the MMBtu needed to run the facility. Fuel oil emissions are inherently limited by existing NOx and SO2 limits (T1-2020.0024). To meet these emission limits and operational requirements, fuel oil is restricted to approximately 4%–5% of the annual MMBtu consumption. Because of this, wood or natural gas must be used as the primary fuel to allow mill operation. See the amendment to Appendix B for the entire justification provided by the facility in the regional haze supplement.
7	Retrofit Factors and Contingency Costs: The justification provided by the company does not address why the retrofit factors identified for Power Boiler No. 4 are appropriate—NPS recommends that a robust justification be provided in the SIP, consistent with EPA cost analysis guidance. In IDEQ’s Response to NPS comments on retrofit factors used in Clearwater Paper’s four-factor analysis (Appendix F), IDEQ notes: “Clearwater had submitted justification for the use of a retrofit factor of 1.5 on March 26, 2020. DEQ had mistakenly not included this submittal in Appendix B. It has now been included.” The NPS has several comments regarding Clearwater’s response to this issue: (1) we recommend that these types of conclusions are based on verifiable information such as vendor’s quotes, and (2) Clearwater’s justification addresses the retrofit factor for the recovery furnaces only. It does not address the retrofit factors used in the power boiler #4 analyses evaluating Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). According to their documentation, Clearwater used a retrofit factor of 1.5 in the SNCR analyses and a retrofit factor of 1.3 in the SCR analyses for both the power boiler and recovery furnaces. The SCR analysis for Power Boiler No. 4 also utilized a 1.3 retrofit factor and included both an indirect “process contingency” annual cost of \$817,714 (5% of TCI) and a “project contingency” annual cost of \$4,906,285 (30% of TCI estimates). These contingency cost estimates were in addition to the higher retrofit factor and seem excessive relative to CCM cost estimate methods. The revised 2019 SCR cost estimation methods presented in the	Vendor quotes were provided as available, such as for LoTOx. Otherwise, EPA’s CCM was used to generate cost estimates. (2) Clearwater justified the retrofit factor for the No. 4 power boiler as follows: “The Clearwater NO. 4 Power Boiler is a field erected hog fuel fired boiler with a design heat input rating of 1,048 mmBtu/hr. It is operating as a swing boiler with swings of up to 150 klb/hr on a daily basis (i.e. ~25% of its design). Per Table 1.3 of the Cost control manual, there is only one similar SNCR cost precedent that was used as the basis for the SNCR cost algorithms. It is for a much smaller hog fuel fired unit. In Table V-4 of the reference it indicates [that SNCR] has been installed on a few new wood boilers to achieve NOX reductions in the 20 to 25% range, [that] SNCR [is] not appropriate for boilers with high load swings, [and] SCR has not been applied. As a result, if it assumed that it is feasible to retrofit an SNCR on a swing boiler such as Clearwater’s No. 4 power boiler, it is also logical to assume that the complexity of the reagent injection system and its controls would also be much greater resulting in a much higher cost to retrofit than is the basis for EPA’s SNCR cost algorithms. As a result, a 1.5 retrofit factor is a reasonable assumption.” Clearwater provided the following justification regarding the use of the 1998 CCM: “This algorithm was used to make a first cut estimate of the cost effectiveness

Comment #	Comment	DEQ Response
	2019 CCM SCR chapter include contingency costs in the capital costs estimates. The CCM SCR Chapter states: <i>“the capital cost equations included in the manual reflect a process contingency of 5 to 10 percent and a project contingency of 15 percent,”</i> highlighting that the contingency costs are not itemized separately from the TCI. (Additional detail on the cost analyses for the power boiler are provided below.) The CCM introduction chapter notes the following with regard to contingency: <i>For mature control technologies, which reflect the control technologies covered in the other chapters of this Manual, the contingency can range from 5 to 15% of the TCI. This contingency is quite consistent with general cost guidance for mature or well-known technologies. Finally, contingency should not account for events such as price escalation, work stoppages, and disasters.</i> The NPS recommends that the default CCM and contingency costs are used in the absence of a robust justification for increased retrofit factors and contingency costs. This includes an assumed retrofit factor of 1.0 for a retrofit of “average difficulty.” The CCM default retrofit factor of 1.0 already assumes costs well above those for a “greenfield” application with a retrofit factor of 0.8.	associated with an SCR retrofit. When the cost effectiveness without escalating the capital costs from 1998 to present day were all well above \$10,000/ton, it was decided to not worry about doing additional refinements. Thus, the conservatively low cost effectiveness were reported. We asked our consultant to rerun the cost. The results of this effort indicate that the cost effectiveness for the No. 4 Power Boiler is \$25,119/ton as compared to the submittals cost effectiveness of \$20,551/ton.” This method is conservative and meets the control cost manual. DEQ evaluated the effect of contingency costs on the cost effectiveness by eliminating contingency costs entirely. This resulted in a conservative cost effectiveness that exceeds \$7,935 per ton. Even with this conservative approach results still demonstrate these controls are not cost effective.
8	Clearwater determined that SCR and SNCR are not technically feasible for recovery furnaces. This determination accurately reflects control system applications for recovery furnaces. As recommended in NPS consultation comments, quaternary air represents a top-level control system application for recovery boilers. Clearwater declined to evaluate this option and question/ed whether this technology has been demonstrated in practice and concluded that based on recent testing for recovery furnace No. 4, quaternary air would achieve minimal NOx reductions. From the Appendix F response to NPS comments: <i>DEQ reached out to Clearwater for response to this issue. In their response, Clearwater first pointed out that the effective date of the permit authorizing the Quaternary Air Injection (QAI) project at the Woodland facility is January 5, 2022; therefore, it is unlikely that this project has been completed, or if so, that it has been operational for long enough to demonstrate its effectiveness. Furthermore, they argued that since QAI had been established as LAER for NOX with 85 ppmvd @ 8% O2 for Woodland, and since the No. 4 Recovery Furnace has been tested at 74 ppmvd at 0% O2, any actual reduction in NOX emissions at the No. 4 Recovery Furnace would be small, rendering the project cost ineffective.</i> With respect to whether quaternary air has been successfully operated in practice, NPS has attached several examples of quaternary air on recovery	In reviewing Clearwater’s past responses regarding QAI (included in Appendix B), DEQ noticed that we had erroneously attributed the 74 ppmvd NOx source test to the No. 4 Recovery Boiler. This test result belongs to the No. 5 Recovery Boiler. The oxygen content of this test was at 8%, not 0%. Additional testing revealed even lower emissions than this test. Testing performed on December 13, 2012, demonstrated NOx emissions of 60 ppm at 8% O2, much lower than LAER established in the Woodland Pulp and Sun Bio Material permits cited by the commenter. This further supports Clearwater’s claim that installing a QAI system would not result in any significant emissions reduction. Clearwater summarized the scope of work required to implement QAI based on a study of the QAI projects noted by commenters. In particular, installation of QAI at the Woodland Pulp facility “included installation of new primary, secondary, and tertiary air port closure plats; a new second level of tertiary air (also known as quaternary air), located 10 to 20 feet above the existing tertiary air ports and registers; two new black liquor openings and six new black liquor stations; and high-volume low-concentration gas collection system modifications. Of particular note in this description of the proposed work is the fact that the existing black liquor injection

Comment #	Comment	DEQ Response
	furnaces. One example is from a recovery boiler at the Sappi Cloquet LLC facility in Minnesota (existing) and the other is from a 2018 Prevention of Significant Determination (PSD) permit determination for the SUN BIO MATERIAL (U.S.) Company facility in Arkansas. Additionally, the NOx emission testing referenced by Clearwater is for Recovery Furnace No. 4 at 0% O₂. Based on the cost spreadsheets provided by IDEQ for Clearwater paper, Recovery Furnace No. 4 is approximately 1/3 of the size of Recovery Furnace No. 5 and emits roughly 1/3 of the NOx of Recovery Furnace No. 5. Please provide current source testing for Recovery Furnace No. 5 as this is the more significant emission source to be considered. NPS recommends that Clearwater evaluate quaternary air as a NOx control option for the recovery furnaces, particularly for recovery furnace No. 5, which is significantly larger than recovery furnace No. 4.	locations and primary, secondary, and tertiary air ports must all be relocated to accommodate the quaternary ports that will be installed 10 to 20 feet above the tertiary ports. Thus, the extent of the work is large, and the amount of unit downtime likely exceeds that of a normal planned outage.... It is unlikely that any quantifiable NOX reduction can be achieved and if a reduction is possible, the extent of work required to implement a QAI system would make the application cost infeasible.” DEQ concurs with this assessment. Regarding the Sun Bio Material permit cited by the commenter, this permit was not issued in 2018 as the commenter implied. The application was submitted in November 2018 but was issued on September 23, 2019, and the QAI system would not have been installed until much later. Because Clearwater had already begun its analysis before this QAI system was operational, it is not reasonable to retroactively use it as an example of an actually installed control technology. No changes were made as a result of this comment.
9	IDEQ determined that both SCR and SNCR exceeded the \$6,100/ton cost-effectiveness threshold established by IDEQ. As noted in section 3.1.2 above, the company estimates for Power Boiler No. 4 included substantial contingency costs and higher-than-average retrofit factors without documentation to justify these assumptions. Based on the cost spreadsheets provided by IDEQ/Clearwater, it appears that an obsolete version of the CCM was used to estimate SCR costs and that Total Capital Investment (TCI) estimates may be based on a 1998 vendor quote for another facility. Row 28 of the SCR tab in Clearwater’s cost calculation spreadsheets indicates an “estimate date” of December 1998 was escalated to 2018 “construction date.” Based on this, it appears that the “vendor quotes” used in Clearwater’s SCR cost estimate are neither site-specific nor recent (24 years old). SCR application has become more routine and widespread in the last 25 years, dramatically reducing costs. In this circumstance, the NPS recommends that the CCM methodology is a more appropriate basis for the SCR cost estimate for Power Boiler No. 4. The NPS recommends that IDEQ correct these issues in the SCR analysis for Power Boiler No. 4. Because the analyses provided by the applicant did not provide fuel characteristics data (e.g., the heat	See NPS comment 7.

Comment #	Comment	DEQ Response
	and moisture content of wood waste fuel, as well as the exact ratios of natural gas and wood waste combusted), we could not re-estimate the costs of SCR. CCM methods indicate that SCR might be \$5,000/ton if 100% natural gas were combusted. Nonetheless, the NPS recognizes that wood waste combustion could increase these cost assumptions and may exceed IDEQ's cost-effectiveness threshold. The NPS recommends that the SIP cost analyses address these details.	
Section 3.2 Itafos Conda LLC		
10	The NPS appreciates IDEQ's response to our analysis for the Itafos Conda east sulfuric acid plant wet packed-tower scrubber cost estimates. Based on this additional information, we made the following revisions to the original analysis: • <u>Purchased equipment costs (PECs)</u>: PECs were based the 2020 Durr Megtec LLC Vendor Quote provided in Appendix B. PEC was escalated from 2020\$ to 2021\$ based on The Chemical Engineering Plant Cost Index (CEPCI = 708.0/596.2). • <u>Interest Rate</u>: The interest rate used in the analysis was adjusted to the current bank prime rate of 4.75%. • <u>Chemical Reagent Costs</u>: These values were updated based on revised analyses provided in Appendix B to the SIP (Itafos Submittal, June 14, 2022). • <u>Assumed Control Efficiency</u>: In response to the NPS analysis, IDEQ noted: <i>NPS adjusted various factors used in the facility's submitted cost-effectiveness calculation. DEQ concurs with the adjusted factors except the following. Sales tax was included. The Durr MEGTEC, LLC vendor quote states expected gas conditions as follows: Inlet SO2 is 135lb/hr and outlet SO2 is 13.5 lb/hr. Therefore, the control efficiency used in the analysis is 90%.</i> The NPS notes that elsewhere the report cites 98% control efficiency but has revised the NPS analysis to reflect 90% control efficiency. • <u>Annual Operating and Maintenance Labor</u>: The original NPS analysis used the CCM default of 0.5 hours per shift—the company analysis assumed 1 hour per shift for these costs. Itafos provided a response to this assumption that included increased operator time per shift due to space constraints that would require manlifts and/or scaffolding and OSHA requirements specific to the facility. While these issues are not likely unique to the Itafos facility, NPS revised the analysis to reflect the Itafos assumptions.	Itafos, after consulting other professionals, determined their previous submittals were significantly flawed and therefore, they redid their analysis to address the deficiencies. Itafos submitted an updated analysis February 29th, 2024. The updated analysis and DEQ's review can be found in Appendix B of the regional haze supplement. DEQ found this analysis to be complete, both wet scrubber technologies were not cost effective for this regional haze implementation period.

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	• <u>Contingency Costs</u>: In the original NPS analysis the default CCM estimate for contingency costs is 10% of annual direct and indirect costs.¹ EPA guidance recommends that ample documentation and justification is provided for analyses that utilize price escalations that exceed the default CCM values. This information was not included in the Itafos analysis. In this case, a scrubber is still likely cost-effective even with a 20% contingency factor. The revised NPS estimates reported in Table 1 above reflect these higher contingency cost estimates to demonstrate cost-effectiveness. All revisions to the NPS analysis are highlighted in bold red text in the attached cost analysis spreadsheets. The revised cost-effectiveness estimates are still well below IDEQ's cost effectiveness threshold. We encourage IDEQ to require the cost-effective SO₂ scrubber options in the regional haze SIP.	
Section 3.3 J.R. Simplot-Don Siding Pocatello		
11	The NPS previously recommended that a wet packed-tower scrubber may be cost effective for the J.R. Simplot sulfuric acid plants No. 300 and No. 400, and that IDEQ include an SO₂ analysis for the sulfuric acid plants in the SIP. The NPS provided a scrubber analysis based on the Itafos information and subsequently revised these estimates based on new information provided in Appendix F and Appendix B as well as more recent economic factors including a revised bank prime rate. To be conservative, in some cases, the NPS analysis included cost estimates that exceed the CCM default values, including increased contingency costs (see Itafos comments in Section 3.2). Based on these revised analyses, the NPS continues to recommend that a wet packed-tower scrubber is likely cost-effective relative to IDEQ's cost threshold and should be evaluated in the SIP. Our revisions are summarized in Table 2. Please see our technical comments submitted during FLM consultation in March 2022 for a full analysis of the J.R. Simplot facility and analysis recommendations.	When EPA issued the Consent Decree to JR Simplot in 2015, the emission limits for the #300 and #400 Sulfuric Acid Plants were considered "BACT equivalent." The emission limits included in the consent decree were consistent with other emission limits for existing facilities listed in the RACT/BACT/LEAR Clearinghouse (RBLC) for similar emission units at the time the consent decree was finalized. DEQ does not agree that a four-factor analysis and additional SO₂ controls are needed for this planning period. DEQ added a summary table from the RBLC for sulfuric acid plants to the four-factor memo for JR Simplot in Appendix B of the August 2022 submittal.
12	IDEQ restricted the scope of Simplot's four-factor analysis to PM₁₀ emissions from the No. 300 Sulfuric Acid Plant and NO_x emissions from the No. 400 Sulfuric Acid Plant based on a 2015 Consent Decree. As noted in the NPS February 2022 consultation comments, emission reductions achieved because of alleged CAA violations do not preclude an analysis of the facility to comply with other CAA requirements, including reasonable progress determinations. Under the CAA,	See response to NPS comment 11.

Comment #	Comment	DEQ Response
	reasonable progress determinations are to be based on the four statutory factors, including the cost of compliance. NPS recommends that IDEQ include a four-factor analysis of potential SO ₂ controls for each of the JR Simplot facility sulfuric acid plants and require cost-effective SO ₂ controls.	
13	The original NPS analysis for J.R. Simplot relied on vendor quotes provided in the Itafos Conda east sulfuric acid plant wet packed tower scrubber cost estimates. IDEQ provided detailed responses to the NPS analysis on Itafos and provided updated information in Appendix B to the SIP. Based on this additional information for the Itafos analysis, the NPS made the following revisions to our original J.R. Simplot analysis: • <u>Purchased equipment costs (PEC)</u>: PECs were based the 2020 Durr Megtec LLC Vendor Quote provided in Appendix B for Itafos and were scaled up for J.R. Simplot using the six tenths power rule. The Itafos PEC was escalated from 2020\$ to 2021\$ based on The Chemical Engineering Plant Cost Index (CEPCI). • <u>Interest Rate</u>: The interest rate used in the analysis was adjusted to the current bank prime rate of 4.75%. • <u>Assumed Control Efficiency</u>: The NPS revised the assumed control efficiency to 90% per IDEQ response to the NPS Itafos analysis (see Section 3.2 above). • <u>Contingency Costs</u>: In the original NPS analysis we note that the default CCM estimate for contingency costs is 10% of annual direct and indirect costs. Based on EPA guidance, ample documentation/justification is required if price escalations that are outside of the CCM default recommendations are utilized, which was not provided for the Itafos assessment. In this case, we used the same contingency factor that had been used by the company in the Itafos analysis because the NPS analysis is based on the Itafos vendor quote. It also demonstrates that a scrubber is still likely cost-effective with a 20% contingency. The revised NPS estimates reported in Table 2 above reflect these higher contingency cost estimates. All revisions to the NPS J.R. Simplot analysis are highlighted in bold red text in the attached cost analysis spreadsheets. The revised cost-effectiveness estimates are still well below IDEQ's cost effectiveness threshold. We encourage IDEQ to evaluate these SO₂ controls for the J.R. Simplot facility and require the cost-effective SO₂ scrubber options in the regional haze SIP.	See response to NPS comment 11
Section 3.4 Northwest Pipeline LLC – Soda Springs		
14	During the FLM consultation period, NPS noted that IDEQ's cost estimate included annual operating costs, such as administration, property tax,	On June 5, 2023, NWP-Soda Springs informed DEQ it intended to replace the three Clark TLA-6 reciprocating engines and

Comment #	Comment	DEQ Response
	insurance, and operating labor, that comprise approximately 40% of the total annual cost. NPS commented that it was not clear why these costs would be incurred for an engine retrofit and suggested that IDEQ clarify how these annual operating costs are applicable to an engine retrofit or re-estimate the cost effectiveness of the LEC retrofits without them. IDEQ responded: “Recurring annual costs such as administration, property tax, insurance and operating labor are allowed by the control cost manual. Northwest Pipeline LLC used the EPA Cost Control Manual default values when calculating the recurring costs above. No changes were made as a result of this comment.” IDEQ is correct that the EPA Cost Control Manual (CCM) generally includes recurring annual costs when estimating pollution control costs. However, the annual costs should be specific to the control option evaluated. The CCM chapters currently address post-combustion control options such as selective catalytic reduction, selective non-catalytic reduction, and wet and dry acid gas scrubbing systems; they do not address combustion control options such as LEC engine retrofits. The CCM web page does, however, link to an EPA report that addresses options for reducing emissions from stationary engines. Combustion controls alter the combustion chamber of the emission unit to fine tune air to fuel ratios, combustion timing and other combustion dynamics to lower peak flame temperature and reduce the formation of thermal NOx. As such, they are inherent to the emission unit itself and the annual costs incurred are different from those associated with post combustion controls (e.g., combustion controls do not require reagents, etc.). The operating costs listed in IDEQ’s cost effectiveness estimates for the RICE engine LEC retrofits includes operating labor, overhead, property tax, administration, and insurance as annual indirect costs. These four costs account for approximately 40% of the total annual costs. It is unclear why engine retrofits would incur these additional costs, particularly at an unmanned facility <i>where the control option is inherent to the operating units</i>. For instance, if property taxes are assessed, would the tax apply to the emission unit itself? Would additional property tax be levied to modify the existing engines? What portion of the tax is for the pollution emitting equipment itself and what portion is assessed for the control modifications? What administration costs are incurred for an unmanned facility and are administration costs are incurred for	the single Clark TCVA-16 reciprocating engine with equipment offering an approximate 98%–99% reduction in emissions. On September 1, 2023, DEQ entered into a compliance agreement schedule (CAS) with NWP-Soda Springs to remove the three Clark TLA-6 engines and one Clark TCVA-16 engine and install and operate the following equipment by July 31, 2031: A. Turbine 1 is a Solar Centaur 40-4700S, 15 parts per million (ppm) NOx unit. This unit is site rated at 3863 horsepower (hp) at 0 degrees Fahrenheit (°F). B. Turbine 2 is a Solar Taurus 70-10802S, 9 ppm NOx unit. This unit is site rated at 9072 hp at 0°F. The CAS is included in Appendix J of the regional haze supplement. Due to the engines being replaced, the comment on the four-factor analysis is now moot. Future changes at the facility will reduce haze causing pollutants and will reduce regional haze overall.

Comment #	Comment	DEQ Response
	an unmanned facility and are these similar to a post-combustion control options at manned facilities? The NPS recommends that IDEQ include additional explanation as to why these costs apply to combustion controls.	
Section 3.5 The Amalgamated Sugar Company (TASCO)		
15	The NPS appreciates IDEQ's detailed responses to our feedback on the TASCO Nampa, Paul and Twin Falls facilities. In particular, Appendix D concisely addressed NPS questions regarding emission unit emissions at these facilities. The NPS appreciates that IDEQ provided this information. The NPS adjusted the recommendations for these facilities based on the additional fuel switch at the Nampa facility proposed in the SIP and current economic factors. Detailed NPS cost analyses are provided in the attached spreadsheets. All TASCO costs analyses were updated to include: • 2021 dollars using the 2021 CEPCI; • A 4.75% interest rate; • Increased reagent costs based on the most recent USGS NH3 commodity price statistics (cited in CCM SCR Chapter). In closing, the NPS encourages IDEQ to secure additional NOx emission reductions through the regional haze SIP by: • Installing SCR on the Riley boiler at the Nampa facility • Installing SCR on the B&W and Foster Wheeler boilers at the Twin Falls facility • Removing coal as an allowable fuel for the pulp dryers at the Paul facility or installing SCR on these units	The original compliance costs indicated these controls were not reasonable to impose. The adjustments only increase the costs and make them even less likely to be required. See responses to comments 15-18.
TASCO – Twin Falls		
16	IDEQ removed coal as an allowable fuel in the B&W Boiler in 2021 and is proposing to convert the Foster Wheeler Boiler from only coal to natural gas by January 1, 2023. As demonstrated in the NPS analyses, SCR is likely still cost-effective for these two boilers, <i>even when combusting natural gas at \$3,249/ton and \$4,642 /ton, respectively</i>. The NPS continues to recommend that IDEQ require SCR to reduce NOx emissions from these units.	DEQ determined that it is not reasonable to require additional controls on these boilers after the coal is removed as a fuel. DEQ views this as requiring double controls on a single emission unit. Overall, the fuel switch will account for a reduction of 500.71 tpy of NOx, which DEQ considers substantial. Table 34 of the August 2022 submittal identifies the NOx, PM10, and SO2 emissions that will be reduced due to the fuel switch.
17	It is unclear what is meant by "over control" of the Foster Wheeler boiler at the Twin Falls facility, but the NPS highlights that SCR is likely cost-effective for this unit even when combusting 100% natural gas (see recommendations above). The NPS revised the SCR cost analyses for the TASCO Twin Falls facility B&W and Foster Wheeler boilers to reflect the recent bank prime rate and 2021 CEPCI value and SCR is likely cost-effective for these units at \$3,153/ton and \$4,546/ton, respectively (see attached spreadsheets).	See response to NPS comment 16.
TASCO – Paul		

Comment #	Comment	DEQ Response
18	No specific actions were proposed by IDEQ for this facility. The NPS continues to recommend that IDEQ remove coal as a fuel for the pulp dryers at this facility to further reduce SO ₂ and NO _x emissions. The NPS previously evaluated SCR for the pulp dryers, under the coal-firing scenario. Under IDEQ's \$6,100/ton cost-effectiveness threshold, current economic factors suggest that fuel switching may be the most viable, cost-effective option at this time. However, SCR is still cost effective if the cost-effectiveness threshold is also adjusted as recommended by the NPS at \$6,508/ton for the north pulp dryer and \$7,291 for the south pulp dryer.	Idaho disagrees that additional controls at the TASCO–Paul facility are needed to meet reasonable progress. The pulp dryer controls proposed by NPS are above DEQ's cost-effectiveness threshold and are not reasonable for the current regional haze implementation period. DEQ provided additional justification for this decision in Section 6.4 and Appendix I of the regional haze supplement.
19	The NPS continues to recommend that IDEQ consider a fuel switch for the pulp dryers at the Paul facility, regardless of the reductions at the Twin Falls facility. In response to IDEQ's justification for eliminating the Paul facility from additional consideration, the NPS notes that visibility benefit and visibility projections relative to the uniform rate of progress (URP) alone are inappropriate for rejecting otherwise cost-effective controls. EPA covered this topic in their July 8, 2021, Clarification Memo (§5.4). The NPS recommends that IDEQ base the reasonable progress determinations on the four statutory factors and require all technically feasible, cost-effective controls identified through four-factor analyses in this planning period.	Idaho is not relying on the URP as a safe harbor but considering visibility impacts in its control determination. EPA interpreted the CAA and RHR as allowing states to consider visibility alongside the four statutory factors when determining the emission reduction measures that are necessary to make reasonable progress (July 2021 clarification memo). Idaho disagrees that additional controls at the TASCO–Paul facility are needed to meet reasonable progress. DEQ provided additional justification for this decision in Section 6.4 and Appendix I of the regional haze supplement.
TASCO – Nampa		
20	The removal of coal as an allowable fuel for the Riley Boiler addresses SO ₂ for this unit, as switching to natural gas significantly reduces SO ₂ emissions. Although NO _x emissions would be reduced with a fuel switch, they are still a concern with natural gas combustion. In the original four-factor analysis, TASCO Nampa declined to consider an enforceable fuel switch. Because of this, the original NPS only evaluated the cost of SCR when combusting coal. The NPS reanalyzed the revised determination to switch to 100% natural gas. NPS analyses show that additional NO _x control with SCR for the Riley Boiler when combusting natural gas is below IDEQ's cost threshold at \$2,826/ton . The NPS recommends that this information is considered in the SIP.	DEQ disagrees that we are required to evaluate additional NO _x controls for the boilers switching from coal to natural gas for this planning period. This is equivalent to requiring double controls on a single emission unit. DEQ also disagrees that switching from coal to natural gas does not decrease NO _x . Table 34 of the August 2022 submittal identifies the NO _x , PM ₁₀ , and SO ₂ emissions that will be reduced due to the fuel switch. Overall, there will be a reduction of 131 tons per year of NO _x .

1.3 National Parks Conservation Association and Coalition to Protect America's National Parks Comments

Comment #	Comment	DEQ Response
Section II. Issues identified in the proposed SIP		
1	Uniform Rate of Progress (URP) is not a "Safe Harbor." it is inappropriate for DEQ to use visibility conditions and the status of the glideslope to justify inaction in this plan and in doing so is failing to make reasonable progress to continue cleaning up haze pollution incrementally. We urge the state to modify the	Idaho is not relying on the URP as a safe harbor but considering visibility impacts in its control determination. EPA interpreted the CAA and RHR as allowing states to consider visibility alongside the four statutory factors when determining the emission

	Proposed SIP by requiring measures of pollution reduction to satisfy the requirement to make reasonable progress, and not lean improperly on the URP to justify doing nothing.	reduction measures that are necessary to make reasonable progress (July 2021 clarification memo).
2	DEQ's Proposed SIP only includes proposed controls for two of its sources: TASCO-Nampa and TASCO-Twin Falls. TASCO-Nampa's commitment to switch from coal to natural gas must be made enforceable in the SIP, there is no regulatory language proposed.	The requirement for TASCO-Nampa to switch from coal to only natural gas was made federally enforceable through a permit. The applicable permit conditions are available in Appendix J of the regional haze supplement.
3	However, it (DEQ's Proposed SIP) does not address the NOx emissions from the B&W Boiler, which the NPS calculated cost-effective for SCR at \$2,433/ton, and we concur with the NPS that DEQ should require. The language for TASCO-Twin Falls does not include any provisions for monitoring, recordkeeping and reporting of emissions. Moreover, in addition to allowing for the use of coal, the Twin Falls proposed SIP provision allows for the use of fuel oil during startup, which DEQ failed to disclose in its Proposed SIP. A Four-Factor Analysis determination applies at all times, and DEQ must remove the option to allow for the use of fuel oil during startup. Once the SIP is revised, DEQ must renotice and provide an opportunity for the public to review and comment.	Both the B&W and the Foster Wheeler boilers have federally enforceable permit conditions to exclusively use natural gas. DEQ determined that it is not reasonable to require additional controls on these boilers after coal is removed as a fuel. DEQ views this as requiring double controls on a single emission unit. Overall, the fuel switch will account for a reduction of 500.71 tpy of NOx, which DEQ considers substantial. Table 34 of the August 2022 submittal identifies the NOx, PM10, and SO2 emissions that will be reduced due to the fuel switch. Applicable permit requirements were included in Section 6.4 of the SIP and Appendix J of the regional haze supplement.
4	Clearwater Paper Corporation: For the Clearwater Paper Corporation and other sources where it relies on this threshold, DEQ must reconsider its \$6,100 cost-effectiveness threshold. DEQ failed to propose SCR controls at Power Boiler 4 based on a cost-effectiveness. DEQ set a cost-effectiveness threshold for the second implementation period of \$6,100/ton. Using such a low threshold, DEQ argued that the figure of \$9,556/ton was greater than the threshold of \$6,100/ton it set. For Power Boiler 4, \$9,556/ton is lower than the cost-effectiveness thresholds being established for the second round regional haze plans by several states, for example Oregon (\$10,000/ton) and Colorado (\$10,000/ton). Therefore, DEQ must include SIP control measures representing SCR controls at Power Boiler 4.	Idaho used the Consumer Price Index (CPI) inflation calculator to escalate a \$5,000 cost threshold from January 2010 to April 2021. Neither the Regional Haze Rule nor guidance requires states to establish a specific cost threshold in determining reasonable progress. For transparency and fairness, Idaho elected to base the cost threshold on prior BART decisions made in the first regional haze implementation period. The threshold is not a direct comparison to capital project spending or industrial goods, so its validity is not tied to a specific escalation index. Idaho's cost threshold allows enough latitude in determining reasonable controls for a complex mix of emission units selected for the four-factor analysis. The threshold neither removes from consideration all technically feasible controls nor automatically considers all controls cost-effective. No changes were made as a result of this comment
5	Itafos Conda LLC: The public lacks information upon which to comment regarding what DEQ is relying on for the Four-Factor Analysis for. For example, the NPS expressed concern that the source revised their cost estimate vendor quotes without justification and DEQ explained, without providing a citation, that "EPA Cost Control Manual allows for a recent vendor quote (within the last 5 years) to be adjusted to current dollars. The cost-effectiveness figure calculated by Itafos is inflated and the NPS's calculations demonstrate that SO2 controls are cost-effective. NPS thus recommended that IDEQ	While investigating the NPS comments on the public comment version of the August 2022 submittal, Itafos, after consulting other professionals, determined their previous submittals were significantly flawed and therefore, they redid their analysis to address the deficiencies. Itafos submitted and updated analysis February 29 th , 2024. The updated analysis and DEQ's review can be found in Appendix B of the regional haze supplement. DEQ found this analysis to be complete, the both wet scrubber technologies were not cost effective for this regional haze implementation period.

	revise the SIP to require SO ₂ scrubbing at the Itafos facility. For this source, the DEQ must provide the public with full documentation of the missing information. DEQ must ensure a Four-Factor Analysis and emission controls are included in the SIP for this source.	
6	J.R. Simplot - Don Siding Pocatello: DEQ erroneously relies on EPA's 2015 Consent Decree as the basis for this source to escape SO₂ controls. This is despite the source ranking number one for SO₂ impacts to Craters of the Moon National Monument and Preserve as well as Yellowstone and Grand Teton National Parks even with the Consent Decree controls in place. As the NPS's comments explained to DEQ, a Four-Factor Analysis is required, DEQ must not rely an outdated EPA agreement, which was not entered into to meet the Clean Air Act's Regional Haze Reasonable Progress Four-Factor Analysis requirements as the basis for the source to escape controls. Moreover, as the NPS comments explained, there are sources will lower SO₂ emission rates in the RACT/BACT/LAER clearinghouse. DEQ must ensure a SO₂ Four-Factor Analysis is conducted and emission controls are included in the SIP for this source. As the NPS' consultation comments explained, additional information, including recent emissions for individual emission units and vendor quotes are necessary to complete a thorough evaluation of the phosphate fertilizer manufacturing source. DEQ must ensure that Four-Factor Analyses are conducted and emission controls are included in the SIP for these plants.	When the EPA issued the Consent Decree to JR Simplot in 2015, the emission limits for the #300 and #400 Sulfuric Acid Plants were considered "BACT equivalent. The emission limits included in the consent decree were consistent with other emission limits for existing facilities listed in the RACT/BACT/LEAR Clearinghouse (RBLC) for similar emission units at the time the consent decree was finalized. DEQ does not agree that a four-factor analysis and additional SO₂ controls are needed for this planning period. DEQ added a summary table from the RBLC for sulfuric acid plants to the four-factor memo for JR Simplot in Appendix B of the August 2022 submittal.
7	Northwest Pipeline LLC-Soda Springs: In response to the NPS's concerns, DEQ offered that the source used EPA's Control Cost Manual but failed to provide citations and discussion. DEQ must consider the information contained in the NPCA-commissioned comprehensive reports on reasonable progress Four-Factor Analysis for the oil and gas industry applicable to natural gas compression stations and this source, which are included as exhibits with these comments	On June 5, 2023, NWP-Soda Springs informed DEQ it intended to replace the three Clark TLA-6 reciprocating engines and the single Clark TCVA-16 reciprocating engine with equipment offering an approximate 98%–99% reduction in emissions. On September 1, 2023, DEQ entered into a CAS with NWP-Soda Springs to remove the three Clark TLA-6 engines and one Clark TCVA-16 engine and install and operate the following equipment by July 31, 2031: A. Turbine 1 is a Solar Centaur 40-4700S, 15 parts per million (ppm) NO_x unit. The unit is site rated at 3863 horsepower (hp) at 0 degrees Fahrenheit (°F). B. Turbine 2 is a Solar Taurus 70-10802S, 9 ppm NO_x unit. The unit is site rated at 9072 hp at 0°F. This CAS is included in Appendix J of the regional haze supplement. Due to the engines being replaced, the comment on the four-factor analysis is now moot. Future changes at the facility will reduce haze causing pollutants and will benefit regional haze overall.

8	P4 Production LLC: DEQ erroneously relies on information in a 2009 BART analysis as its basis to avoid the required Four-Factor Analysis. The analysis is outdated, and as the NPS's comments indicate, at least one other source in the U.S. has successfully installed a SCR on a rotary kiln. Therefore, DEQ must ensure that a Four-Factor Analysis is conducted for P4 Production LLC.	There was a BART analysis completed in 2009. "Selective catalytic reduction: Not included in the RBL. If a SCR system were installed at the back end of the kiln prior to the particulate control system, the heavy particulate loading in the gas stream would foul the catalyst. Also, the temperature of the kiln off gas would be much too high for SCR to be effective. SCR is only effective in a temperature range of 300°C to 400oC (572 oF to 752 oF). If the SCR system were installed after the particulate control system to prevent catalysts fouling, the temperature of the gas stream would be too low for SCR to function properly. Also, the high moisture content in the gas stream after the particulate control system would cause the SCR system to be inoperable due to water molecules coating the surface of the catalyst and preventing mass transfer for the catalytic reaction to occur." P4 analyzed the technical feasibility of installing SCR on the rotary kiln at P4 Production LLC. DEQ reviewed the analysis and concurred that this alternative is infeasible on this unit.
9	TASCO—Paul, Twin Falls, Nampa: For all three sources DEQ uses methodology that does not comport with EPA's Control Cost Manual, which the NPS documented, and DEQ ignored. Moreover, each of the emission unit source must be evaluated under a Four-Factor Analysis and controls applied. DEQ's proposed approach of allowing for over control at the Twin Falls source to in effect offset controls at the other sources is not provides for under the Act and EPA's regulation. Moreover, DEQ's argument that its Class I areas are under the URP also fails. Controls must be established this planning period. Visibility is not a fifth factor; the Act only has "four" factors. Finally, as the NPS's comments elaborate, and DEQ failed to respond to, DEQ's control efficiency control estimates were both too low and failed to provide adequate justification for the estimates.	DEQ air quality engineers reviewed each facility's four-factor analysis submittals to ensure they followed the EPA cost control manual or provided sufficient justification for their approach. DEQ worked with facilities to use site-specific information when available. When facilities did not use EPA-recommended values for interest rate and equipment life, DEQ adjusted the submitted cost analysis to recalculate the cost-effectiveness using the EPA-recommended values. These adjusted values are included in Appendix B of the August 2022 submittal, where applicable. Both the B&W and the Foster Wheeler boilers at TASCO—Twin Falls have federally enforceable permit conditions to exclusively use natural gas. Idaho is not relying on the URP as a safe harbor but considering visibility impacts in its control determination. EPA interpreted the CAA and RHR as allowing states to consider visibility alongside the four statutory factors when determining the emission reduction measures that are necessary to make reasonable progress (July 2021 EPA clarification memo). Idaho disagrees that additional controls at the TASCO—Paul facility are needed to meet reasonable progress. DEQ provided additional justification for this decision in Section 6.4 and Appendix I of the regional haze supplement. The requirement for TASCO—Nampa to switch from coal to only natural gas was made federally enforceable through a permit. The applicable permit conditions are available in Appendix J of the regional haze supplement.

Section II.C DEQ Must Analyze Environmental Justice Impacts of its Regional Haze SIP, and Must Ensure Its SIP Will Reduce Emissions and Minimize Harms to Disproportionately Impacted Communities		
10	DEQ completely ignored the environmental justice communities impacted by Idaho's polluting sources. Sources that harm the air in our treasured Class I areas are also located in environmental justice areas across the State. By evaluating the vulnerable communities and counties impacted by these sources, we believe DEQ will identify emission-reducing options that if required will improve air quality and help achieve reasonable progress in this round of regional haze rulemaking.	Environmental Justice is not required, per the CAA or RHR, for this Regional Haze SIP.
11	EPA will be required to ensure that its action on DEQ's Haze Plan addresses any disproportionate environmental impacts of the pollution that contributes to haze, and is subject to the current Administration's "Executive Order on Tackling the Climate Crisis at Home and Abroad." DEQ can facilitate EPA's consideration of environmental justice to comply with Federal Executive Orders. Idaho can facilitate EPA's compliance with these Executive Orders by considering environmental justice in its SIP submission.	Environmental Justice is not required, per the CAA or RHR, for this Regional Haze SIP.
12	DEQ ignored EPA's Regional Haze Guidance and Clarification Memo, which directs states to take environmental justice concerns and impacts into consideration. States may also consider any beneficial non-air quality environmental impacts. ¹⁸ This includes consideration of environmental justice in keeping with other agency policies. When there are significant potential non-air environmental impacts, characterizing those impacts will usually be very source- and place-specific. Other EPA guidance intended for use in environmental impact assessments under the National Environmental Policy Act may be informative, but not obligatory to follow, in this task. Idaho should consider these sources of information in conducting a meaningful environmental justice analysis.	Environmental Justice is not required, per the CAA or RHR, for this Regional Haze SIP.
13	EPA must consider environmental justice when it reviews and takes action on Idaho's SIP. As occurred in the first planning period, if a state fails to submit its SIP on time, or if EPA finds that all or part of a state's SIP does not satisfy the Regional Haze regulations, then EPA must promulgate its own Federal Implementation Plan ("FIP") to cover the SIP's inadequacy. Consequently, should EPA promulgate a FIP for Idaho sources, it has an obligation to integrate Environmental Justice principles into its decision-making. The non-air quality environmental impacts of compliance portion of the third factor, is a pathway for doing so.	Environmental Justice is not required, per the CAA or RHR, for this Regional Haze SIP.
14	DEQ must consider environmental justice under Title VI of the Civil Rights Act. As EPA must consider Environmental Justice, so must DEQ and all other entities that accept Federal funding. Under Title VI of the Civil Rights Act of	Environmental Justice is not required, per the CAA or RHR, for this Regional Haze SIP. DEQ provided a 30-day public comment period for the August 2022 submittal, with notice provided in a

	1964, “no person shall, on the ground of race, color, national origin, sex, age or disability be excluded from participation in, be denied the benefits of, or be subjected to discrimination under any program or activity...”. DEQ has an obligation to ensure the fair treatment of communities that have been environmentally impacted by sources of pollution. That means going beyond the flawed analysis conducted and ensuring “meaningful involvement” of impacted communities; environmental justice also requires the “fair treatment” of these communities in the development and implementation of agency programs and activities, including those related to the SIP. DEQ must conduct a thorough analysis of the current and potential effects to impacted communities from sources considered in the SIP. By not conducting this analysis and including the benefits of projected decline in emissions to these communities in their determination of the included emission sources, Idaho is not fulfilling its obligations under the law. Moreover, the state is making a mockery of Title VI by not using the SIP requirements to bring about the co-benefits of stronger reductions measures and reduce harms based on continued emissions.	press release and on our website. DEQ also provided the opportunity for translations of documents and interpreters during the public comment period. DEQ complied with the Title VI of the Civil Rights Act of 1964 and did not discriminate or deny benefits to any person based on race, color, national origin, sex, age or disability with regards to the Regional Haze SIP.
15	In conclusion, we request that DEQ revise the Proposed SIP in the following ways before submitting to the EPA: 1. Remove the inappropriate reference to the URP as a “safe harbor.” That Idaho’s Class 1 areas are on the so-called glidepath is not an excuse for avoiding emission reductions. 2. Require additional SIP measures of air pollution reduction in order to satisfy the Act’s requirement that reasonable progress is being made. 3. Reduce impacts of air pollution at both the Class I areas and on the environmental justice communities.	1. Idaho is not relying on the URP as a safe harbor but considering visibility impacts in its control determination (NPCA Comment 9). 2. Idaho has required emissions reductions as well as preventing further degradation to visibility but included existing permit conditions in the SIP to be federally enforceable a result of the Regional Haze SIP (NPCA Comment 9). 3. The emission reductions that have resulted from the regional haze process will have a positive impact on Class I areas and surrounding communities by reducing pollution. Environmental Justice is not required, per the CAA or RHR, for the Regional Haze SIP (NPCA Comment 10-12).

1.4 Amalgamated Sugar Company Comments

Comment #	Comment	DEQ Response
1	I was reading through your SIP because I hadn’t read it yet and I had a little time with it but, I was reading on page 82, pdf page 82, it’s document page 69 where it is talking about Amalgamated Sugar and the information below table 34. One paragraph talks about the B&W boiler and the annual emission reduction of 694 tons, in the following paragraph it talks	DEQ made the necessary correction to address this comment in the August 2022 submittal on page 69.

	about the Foster-Wheeler boiler conversion to natural gas the change at the end of that paragraph for the Foster-Wheel boiler change is 693.9 tons per year, which matches what it says for the B&W Boiler in table 34. I went ahead and looked forward and table 35 of the documents on page 72 of the document, it looks like it says 775.85 tons reduction for the Foster-Wheeler conversion to natural gas. So, page 69, last paragraph probably need to make an adjustment to that number instead of 693 it's 775 something and I think there's another paragraph at page 70 bottom of the page where it also talks about Foster-Wheeler conversion at 693.9. It would be 775.85.	
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2 SIP Supplement Response to Public Comments

To be addressed after the public comment period.

Appendix I. Justification for Not Requiring Controls at Amalgamated Sugar Company LLC – Paul (New)

For the current planning period, DEQ determined that the following controls at the TASCO – Twin Falls and Nampa facilities met reasonable progress for the TASCO company as a whole, and no additional controls at the Paul facility were required to meet reasonable progress:

- Remove coal as an allowable fuel for the Riley boiler by July 1, 2027, at the TASCO – Nampa facility. (Permit # 2018.0011 dated February 15, 2023).
- Remove coal as an allowable fuel for the B&W boiler at the TASCO – Twin Falls facility. (T1-2022.0016, January 9, 2023).

TASCO also made the following emission reductions, considered above and beyond reasonable progress controls, at their Twin Falls facility:

- Convert the Foster Wheeler boiler from only coal to only natural gas with LNB no later than January 1, 2023 (T1-2022.0016, January 9, 2023).

DEQ based this decision on the following:

- The total emissions ($PM_{10}+NO_x+SO_2$) reduced due to the controls listed above is 101.4 tons per year greater than the total emissions that would have been reduced due to the best controls identified through the four-factor analysis for the Twin Falls and Paul facilities.
- The Twin Falls facility impacts visibility in more Class I areas to a greater extent than the Paul facility.
- The Twin Falls and Paul facilities are both owned by the same farmer's cooperative and are in close proximity to each other.

1 Four Factor Analysis Results

For the TASCO – Paul facility, several control options for the north and south pulp dryers and one for the Rentech boilers had cost effectiveness less than the established threshold of \$6,100 (August 2022 submittal, Table 33). The control options with the greatest emission reductions for each emission unit are listed in Table I-1. These control options include removing coal as a fuel (switch to natural gas only) for both pulp dryers and installing ultra-low NO_x burners (UNLB) for the Rentech boiler for a total reduction of 333.48 tons per year of NO_x , SO_2 and PM_{10} combined.

Table I-1. TASC0 – Paul best cost-effective controls from four-factor analysis.

Emission unit	Pollutants for 4FA	Best Control Option	% control	Annual Emission Reductions (t/yr)
North Pulp Dryer	NOx	Switch to NG only ^a	88%	150.37
	SO ₂	Switch to NG only ^a	99%	9.05
	PM ₁₀	Switch to NG only ^a	0	0
South Pulp Dryer	NOx	Switch to NG only ^a	87%	118.45
	SO ₂	Switch to NG only ^a	99%	7.51
	PM ₁₀	Switch to NG only ^a	0%	0
Rentech Boiler	NOx	ULNB		48.1
Total				333.48

For the TASC0 – Twin Falls facility, several control options for the Foster Wheeler and B&W boilers had cost effectiveness less than the established threshold of \$6,100 (August 2022 submittal, Table 34). The control options with the greatest emission reductions for each emission unit are listed in Table 2. These control options include removing coal as a fuel (switch to natural gas only) for the B&W boiler and installing SNCR and dry FGD for the Foster Wheeler boiler for a total reduction of 1034.9 tons per year of NO_x, SO₂, and PM₁₀ combined.

Table I-2. TASC0 – Twin Falls best controls from four-factor analysis.

Emission unit	Pollutant	Best Control Option	% Control	Annual Emission Reductions (tpy)
Foster Wheeler Boiler	NO _x	SNCR	30	90.8
	SO ₂	Dry FGD	50	250.2
	PM ₁₀	current FFB	0	0
Unit Total				341
B&W Boiler	NO _x	Existing Primary Fuel Replacement ^a	50	126.39
	SO ₂	Existing Primary Fuel Replacement	100	556.43
	PM ₁₀	Existing Primary Fuel Replacement		11.08
Unit Total				693.9
Facility Total				1,034.9

a. Remove coal as a fuel option so the emission unit only uses natural gas.

The maximum potential annual emission reductions if the best cost-effective controls were implemented at both facilities would be 1,386.38 tons per year of NO_x, PM₁₀, and SO₂.

2 Over-Control Analysis

After DEQ made the determination regarding reasonable progress controls for the Twin Falls facility, DEQ received an application from TASCO – Twin Falls to convert the Foster Wheeler boiler from only coal to only natural gas by January 1, 2023. As stated in section 6.4 of the SIP, this fuel switch is part of Idaho’s reasonable progress controls for this planning period.

The conversion of the Foster Wheeler boiler from coal to natural gas at the Twin Falls facility has resulted in a reduction of 775.9 tons per year of NO_x, PM₁₀, and SO₂ (Table 3).

Table I-3. Federally enforceable emission reductions due to fuel switch on the Foster Wheeler boiler at TASCO – Twin Falls.

Pollutants for 4FA	2014 Baseline	% Control	Projected Emissions	Annual Emission Reductions (tpy)
NO _x	302.59	80	59.30	243.29
SO ₂	500.41	100	0.50	499.91
PM ₁₀	38.2	86	5.50	32.70
NO_x+SO₂+PM₁₀				775.90

The emissions reduced due to switching the Foster Wheeler boiler from coal to natural gas far exceeds the emission reductions (434.9 tons per year of NO_x, PM₁₀, and SO₂) that would have been realized if the controls listed in Table 2 were required.

Table 4 shows that Idaho’s reasonable progress controls will result in an additional 101.42 tons per year of NO_x, SO₂, and PM₁₀ than would have been achieved if the best controls identified through the four-factory analysis were required.

Table I-4. Total federally enforceable emission reductions at TASCO – Twin Falls.

Facility	Control Scenario	Annual Emission Reductions (tpy)			
		NO _x	SO ₂	PM ₁₀	Total
TASCO – Paul	4FA best control ^a	316.92	16.56	0	333.48
TASCO – Twin Falls	4FA best control ^b	217.19	806.63	11.08	1034.9
Total potential emission reductions - 4FA best controls		534.11	823.19	11.08	1368.38

a. Emission reductions from Table I-1

b. Emission reductions from Table I-2

Table I-5. Idaho’s determination on controls necessary for reasonable progress.

Facility	Control Scenario	Annual Emission Reductions (tpy)			
		NO _x	SO ₂	PM ₁₀	Total
TASCO – Twin Falls	DEQ Proposed controls ^a	369.68	1056.34	43.78	1469.80
Difference between 4FA controls and DEQ proposed controls^b		164.43	-233.15	-32.70	-101.42

a. Emission reductions from Table 3 plus emission reductions for the B&W boiler from Table 2.

b. A negative number indicates DEQ-proposed controls results in greater emission reductions than those resulting from the best cost-effective controls at both the Paul and Twin Falls facilities.

3 Visibility Impacts

The TASCO – Twin Falls is located 38 miles west-southwest of TASCO – Paul. Both facilities impact the same Class I areas. The rank point from the weighted emissions potential (WEP) analysis demonstrates that not only does TASCO – Twin Falls impact visibility at more Class I areas, but it also has a greater impact on those Class I areas than TASCO – Paul in the region, particularly from sulfate precursors (August 2022 submittal, Tables 23 and 24).

The rank point analysis consists of facility-level 2028 emissions for NO_x or SO₂ sources overlaid with the corresponding extinction-weighted residence time for ammonium nitrate or ammonium sulfate. This analysis shows that sulfate and nitrate emissions from TASCO – Paul are impacting visibility at fewer Class I areas and to a smaller extent than TASCO – Twin Falls (Tables I-6 and I-7). The addition of controls at TASCO – Twin Falls will have a greater overall impact on visibility.

Table I-6. Rank of Idaho facilities for SO₂ emissions impacting Class I areas. The darker the cell shading indicates the larger potential impacts on visibility.

Class I Area Monitor	Class I Area State	TASCO – Paul	TASCO – Twin Falls
CRMO1	ID	5	2
SAWT1	ID		2
SULA1	ID		7
GLAC1	MT		9
MONT1	MT		6
JARB1	NV		2
HECA1	OR		3
BRID1	WY		10
NOAB1	WY		9
YELL2	WY		5

Table I-7. Rank of Idaho facilities for NO_x emissions impacting Class I areas. The darker the cell shading indicates the larger potential impacts on visibility.

Class I Area Monitor	Class I Area State	TASCO – Paul	TASCO – Twin Falls
BRID1	WY		
CAB11	MT		
CRMO1	ID	2	1
GAMO1	MT		
GLAC1	MT		
HECA1	OR		6
JAB1	NV	10	1
MONT1	MT		
NOAB1	MT		
SAWT1	ID		7
STAR1	OR		

Class I Area Monitor	Class I Area State	TASCO – Paul	TASCO – Twin Falls
SULA1	ID		
ULBE1	MT		
YELL2	WY	5	6

Appendix J. Redacted Permits and Attachments for Regional Haze (New)

1. Clearwater Paper Corp.—Pulp and Paperboard Division Redacted Permits
2. Itafos Conda, LLC. Redacted Permit
3. J.R. Simplot Company—Don Siding Plant Redacted Permit
4. Northwest Pipeline—Soda Springs Compliance Agreement Schedule
5. P4 Production LLC Redacted Permit and Compliance Agreement Schedule
6. Tamarack Mill, LLC dba Evergreen Forest and Tamarack Energy Partnership Redacted Permit
7. The Amalgamated Sugar Company—Nampa Redacted Permit
8. The Amalgamated Sugar Company—Paul Redacted Permit
9. The Amalgamated Sugar Company—Twin Falls Redacted Permit