THE AMALGAMATED SUGAR COMPANY LLC
PO BOX 8787 • NAMPA, IDAHO 83687 • PHONE (208) 466-3541

December 18, 2015

Idaho Department of Environmental Quality
Air Quality Permit to Construct Fees
Fiscal Office
1410 N. Hilton
Boise, ID 83706-1255

RE: Permit to Construct (PTC) Application
Natural Gas Firing Only Project – No. 1 & No. 2 B&W Boilers
The Amalgamated Sugar Company LLC (TASCO)
Nampa Facility (Facility ID No. 027-00010)

Dear Sir or Madam:

Enclosed is the $1,000 check for the application fee for the Permit to Construct (PTC) Application for the No. 1 and No. 2 B&W boilers natural gas firing project at the Nampa facility.

If you have any questions, please call Glen Patrick at (208) 466-3541.

Sincerely,

Eric C. Erickson, PE, CEM
Plant Manager
Nampa Facility

DCD/ee/ss

Enclosure

Cc: Boise – Joe Huff, Scott Blickenstaff, Dean C. DeLorey
Nampa – Glen Patrick

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DEPARTMENT OF ENVIRONMENTAL QUALITY
STATE A Q PROGRAM

THE AMALGAMATED SUGAR COMPANY LLC

PO BOX 8787 • NAMPA, IDAHO 83687 • PHONE (208) 466-3541

December 18, 2015

William Rogers, Stationary Source Permit Program Coordinator
Air Quality Division
Idaho Department of Environmental Quality
1410 N. Hilton
Boise, ID 83706-1255

RE: Permit to Construct (PTC) Application
Natural Gas Firing Only Project – No. 1 and No. 2 B&W Boilers
The Amalgamated Sugar Company LLC (TASCO)
Nampa Facility (Facility ID No. 027-00010)

Dear Bill,

On October 8, 2015 Amalgamated Sugar Company representatives appreciated the opportunity to meet with you and other IDEQ representatives to discuss the proposed No. 1 and No. 2 B&W boilers natural gas firing only project at the Nampa facility. As presented in this application, the Nampa facility will discontinue the use of coal in the B&W boilers. IDEQ has requested this PTC application to address the Industrial Boiler Maximum Achievable Control Technology (MACT) and Tier II Best Available Control Technology (BART) Operating Permit requirements. As documented in the attached application, this project will result in significant emission decreases. The application is divided into the following sections:

- Section 1 – Application Forms
- Section 2 – Project & Facility Descriptions
- Section 3 – Process Flow Diagrams
- Section 4 – Regulatory Analysis & Emissions Evaluation
- Section 5 – Emissions Estimates & Limitations
- Section 6 – Ambient Air Quality Impact Exemption Analysis

The target completion date for natural gas firing only in the B&W boilers is by the January 31, 2016 Industrial Boiler MACT compliance deadline.

As previously discussed, this PTC application has also been prepared to address Compliance Schedule 14 of Tier I Operating Permit No. T1-050020. Compliance Schedule 14 requires the Nampa facility to evaluate PTC requirements for a selected list of equipment and other applicable historic projects at the facility. Section 4 of the PTC application provides a detailed regulatory analysis of equipment changes including emissions reduction projects. This equipment review analysis is an update to a previous application submitted to IDEQ in 2004.

The application provides supporting documentation that overall facility-wide emissions have decreased over the past 35 years. These decreases are primarily attributable to: 1) The $20 million pulp steam dryer project completed in December 2006 which eliminated three coal-fired pulp dryers; 2) Continuous facility-wide energy conservation and reuse projects; 3) Boiler fuel switching from coal to gas; and 4) Other emissions reduction projects.

If you have any questions, please call Glen Patrick at (208) 468-6883 or Dean C. DeLorey at (208) 383-6500.

Sincerely,

Eric C. Erickson, PE, CEM
Plant Manager
Nampa Facility

EE/dd/ss

Cc: IDEQ – Boise Regional Office
Boise Office – Joe Huff, Scott Blickenstaff, Dean DeLorey
Nampa Facility – Glen Patrick

Index

Permit to Construct (PTC) Application
B&W Boiler Natural Gas Conversion Project
Nampa Facility
December 2015

Section 1 – IDEQ Permit Forms

The following IDEQ Permit Forms are included with this Permit to Construct Application:

Form CSPTC – Cover Sheet for Air Permit Application
Form GI – General Information
Form EU0 – Emission Units *No.1 & No. 2 Babcock & Wilcox (B&W) Boilers*
Form EU5 – Industrial Boiler Information
Form FRA – NSPS/NESHAPS Regulatory Review and Applicability Form
Emissions Inventory Summary Forms:

- Facility Wide PTE
- Proposed Modification at a Major Facility Inventory (Non-PSD)
- Toxic Air Pollutant Inventory
- Hazardous Air Pollutant Inventory

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Cover Sheet for Air Permit Application – Permit to Construct Form CSPTC

Please see instructions on page 2 before filling out the form.

COMPANY NAME, FACILITY NAME, AND FACILITY ID NUMBER			
1. Company Name	The Amalgamated Sugar Co. LLC (TASCO)		
2. Facility Name	Nampa	3. Facility ID No.	027-00010
4. Brief Project Description - One sentence or less	No. 1 & No. 2 B&W Boilers Natural Gas Only Project		

PERMIT APPLICATION TYPE

5. ☐ New Source New Source at Existing Facility ☐ PTC for a Tier I Source Processed Pursuant to IDAPA 58.01.01.209.05.c
☐ Unpermitted Existing Source ☐ Facility Emissions Cap ☐x Modify Existing Source: Permit No.: T1-050020 Date Issued: 12/12/2002
☐ Required by Enforcement Action: Case No.: ____

6. X Minor PTC ☐ Major PTC

FORMS INCLUDED

Included	N/A	Forms	DEQ Verify
X	☐	Form CSPTC – Cover Sheet	☐
X	☐	Form GI – Facility Information	☐
X	☐	Form EU0 – Emissions Units General	☐
☐	X	Form EU1– Industrial Engine Information Please specify number of EU1s attached:	☐
☐	X	Form EU2– Nonmetallic Mineral Processing Plants Please specify number of EU2s attached:	☐
☐	X	Form EU3– Spray Paint Booth Information Please specify number of EU3s	☐
☐	X	Form EU4– Cooling Tower Information Please specify number of EU3s attached:	☐
X	☐	Form EU5 – Boiler Information Please specify number of EU4s attached:	☐
☐	X	Form CBP– Concrete Batch Plant Please specify number of CBPs	☐
☐	X	Form HMAP – Hot Mix Asphalt Plant Please specify number of HMAPs attached:	☐
☐	X	PERF – Portable Equipment Relocation Form	☐
☐	X	Form AO – Afterburner/Oxidizer	☐
☐	X	Form CA – Carbon Adsorber	☐
☐	X	Form CYS – Cyclone Separator	☐
☐	X	Form ESP – Electrostatic Precipitator	☐
☐	X	Form BCE– Baghouses Control Equipment	☐
☐	X	Form SCE– Scrubbers Control Equipment	☐
☐	X	Form VSCE – Venturi Scrubber Control Equipment	☐
☐	X	Form CAM – Compliance Assurance Monitoring	☐
X	☐	Forms EI-CP1 - EI-CP4– Emissions Inventory– Criteria pollutants	☐
X	☐	PP – Plot Plan	☐
☐	X	Forms MI1 – MI4 – Modeling (Excel workbook, all 4 worksheets)	☐
X	☐	Form FRA – Federal Regulation Applicability	☐

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Air Permit Hotline – 1-877-5PERMIT

General Information **Form GI**
Revision 7
1/15/10

Please see instructions on page 2 before filling out the form.

All information is required. If information is missing, the application will not be processed.

IDENTIFICATION	
1. Company Name	The Amalgamated Sugar Company LLC
2. Facility Name (if different than #1)	Nampa Facility
3. Brief Project Description:	B&W Boilers Natural Gas Conversion Project
FACILITY INFORMATION	
4. Owned/operated by: (√ if applicable)	☐ Federal government ☐ County government ☐ State government ☐ City government
5. Primary Facility Permit Contact Person/Title	Eric Erickson, Plant Manager
6. Telephone Number and Email Address	(208) 468-6826 - eerickson@amalsugar.com
7. Alternate Facility Contact Person/Title	Glen Patrick, District Environmental Manager
8. Telephone Number and Email Address	(208) 468 6883 - gpatrick@amalsugar.com
9. Address to which permit should be sent	138 W Karcher Road
10. City/County//State/Zip	Nampa, Canyon County, Idaho 83687
11. Equipment Location Address (if different than #10)	
12. City/County//State/Zip	
13. Is the Equipment Portable?	☐ Yes ☒ No
14. SIC Code(s) and NAICS Code	**Primary SIC:** 2063 **Secondary SIC (if any):** **NAICS:**
15. Brief Business Description and Principal Product	Beet Sugar Manufacturing
16. Identify any adjacent or contiguous facility that this company owns and/or operates	None
PERMIT APPLICATION TYPE	
17. Specify Reason for Application	☒ Permit to Construct (PTC) For Tier I permitted facilities only; if you are applying for a PTC then you must also specify how the PTC will be added to the Tier I permit. ☐ Add PTC at time of Tier I renewal ☐ Co-process Tier I Modification & PTC ☒ Administratively amend Tier I to add PTC upon your request (IDAPA 58.01.01.209.05. a, b or c) ☐ Tier I Permit ☐ Tier II Permit ☐ Tier II/Permit to Construct

CERTIFICATION

IN ACCORDANCE WITH **IDAPA 58.01.01.123** (RULES FOR THE CONTROL OF AIR POLLUTION IN IDAHO), I CERTIFY BASED ON INFORMATION AND BELIEF FORMED AFTER REASONABLE INQUIRY, THE STATEMENTS AND INFORMATION IN THE DOCUMENT ARE TRUE, ACCURATE, AND COMPLETE.

18. Responsible Official's Name/Title	Eric C. Erickson, PE, CEM, Plant Manager	
19. RESPONSIBLE OFFICIAL SIGNATURE		**Date:** 12/18/15

20. ☒ Check here to indicate you would like to review a draft permit prior to final issuance.

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION		
1. Company Name: The Amalgamated Sugar Co. LLC	2. Facility Name: Nampa	3. Facility ID No: 027-00010
4. Brief Project Description:	No. 1 & No. 2 B&W Boilers Natural Gas Firing Only Project	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION		
5.	Emissions Unit (EU) Name:	BABCOCK & WILCOX (B&W) BOILER #1
6.	EU ID Number:	S-B1
7.	EU Type:	☐ New Source ☐ Unpermitted Existing Source ☒ Modification to a Permitted Source -- Previous Permit #:T1-050020 Date Issued: 12/12/02
8.	Manufacturer:	BABCOCK & WILCOX
9.	Model:	
10..	Maximum Capacity:	STEAM - 105,000 LBS/H
11.	Date of Construction:	1942
12.	Date of Modification (if any):	NONE
13.	Is this a Controlled Emission Unit?	☒ No ☐ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT	
14. Control Equipment Name and ID:	None for natural gas firing
15. Date of Installation:	16. Date of Modification (if any):
17. Manufacturer and Model Number:	
18. ID(s) of Emission Unit Controlled:	
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☐ No
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☐ No (If Yes, attach and label manufacturer guarantee)

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. See narrative discussion in Section 5 - Emissions Estimates of this application.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)		
22.	Actual Operation:	24 HOURS PER DAY, 200 DAYS PER YEAR
23.	Maximum Operation:	24 HOURS PER DAY, 365 DAYS PER YEAR

REQUESTED LIMITS		
24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
The Amalgamated Sugar Co. LLC	Nampa	027-00010
4. Brief Project Description:	No. 1 & No. 2 B&W Boilers Natural Gas Firing Only Project	

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	BABCOCK & WILCOX (B&W) BOILER #2
6.	EU ID Number:	S-B2
7.	EU Type:	☐ New Source ☐ Unpermitted Existing Source ☒ Modification to a Permitted Source -- Previous Permit #:T1-050020 Date Issued: 12/12/02
8.	Manufacturer:	BABCOCK & WILCOX
9.	Model:	
10..	Maximum Capacity:	STEAM - 105,000 LBS/H
11.	Date of Construction:	1942
12.	Date of Modification (if any):	NONE
13.	Is this a Controlled Emission Unit?	☒ No ☐ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	None for natural gas firing
15. Date of Installation:	16. Date of Modification (if any):
17. Manufacturer and Model Number:	
18. ID(s) of Emission Unit Controlled:	
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☐ No
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☐ No (If Yes, attach and label manufacturer guarantee)

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency. See narrative discussion in Section 5 - Emissions Estimates of this application.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	24 HOURS PER DAY, 200 DAYS PER YEAR
23.	Maximum Operation:	24 HOURS PER DAY, 365 DAYS PER YEAR

REQUESTED LIMITS

24. Are you requesting any permit limits? ☐ Yes ☒ No (If Yes, indicate all that apply below)

- ☐ Operation Hour Limit(s):
- ☐ Production Limit(s):
- ☐ Material Usage Limit(s):
- ☐ Limits Based on Stack Testing: Please attach all relevant stack testing summary reports
- ☐ Other:

25. Rationale for Requesting the Limit(s):

DEQ AIR QUALITY PROGRAM
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For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Units - Industrial Boiler Information **Form EU5**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3 Facility ID No:
The Amalgamated Sugar Co. LLC (TASCO)	Nampa	027-00010
4. Brief Project Description:	No. 1 & No. 2 B&W Boiler Natural Gas Only Project	

EXEMPTION

Please see IDAPA 58.01.01.222 for a list of industrial boilers that are exempt from Permit to Construct requirements.

BOILER (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS

5. Type of Request: ☐ New Unit ☐ Unpermitted Existing Unit ☒ Modification to a Unit with Permit #:027-00010

6. Use of Boiler: ☒ % Used For Process ☐ % Used For Space Heat ☒ % Used For Generating Electricity ☐ Other:

7. Boiler ID Number: S-B1	8. Rated Capacity: ☒ 126 Million British Thermal Units Per Hour (MMBtu/hr) ☒ 105 1,000 Pounds Steam Per Hour (1,000 lb steam/hr)	
9. Construction Date: 1942	10. Manufacturer: Babcock & Wilcox	11. Model:
12. Date of Modification (if applicable): None	13. Serial Number (if available): None	14. Control Device (if any): None for nat. gas **Note: Attach applicable control equipment form(s)**

FUEL DESCRIPTION AND SPECIFICATIONS

15. Fuel Type	☐ Diesel Fuel (#) (gal/hr)	☒ Natural Gas (cf/hr)	☐ Coal (unit: /hr)	☐ Other Fuels (unit: /hr)
16. Full Load Consumption Rate		123000		
17. Actual Consumption Rate		111000		
18. Fuel Heat Content (Btu/unit, LHV)		1028		
19. Sulfur Content wt%		Negligible		
20. Ash Content wt%		N/A		

STEAM DESCRIPTION AND SPECIFICATIONS

21. Steam Heat Content	NA	NA		
22. Steam Temperature (^{o}F)	N/A	N/A		
23. Steam Pressure (psi)	N/A	N/A		
24 Steam Type	N/A	N/A	☐ Saturated ☐ Superheated	☐ Saturated ☐ Superheated

OPERATING LIMITS & SCHEDULE

25. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):	None
26. Operating Schedule (hours/day, months/year, etc.):	24h/d, 12mo/y
27. NSPS Applicability: ☐ Yes ☒ No	If Yes, which subpart:

DEQ AIR QUALITY PROGRAM
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For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Units - Industrial Boiler Information **Form EU5**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION		
1. Company Name: The Amalgamated Sugar Co. LLC (TASCO)	2. Facility Name: Nampa	3 Facility ID No: 027-00010
4. Brief Project Description:	No. 1 & No. 2 B&W Boiler Natural Gas Only Project	

EXEMPTION

Please see IDAPA 58.01.01.222 for a list of industrial boilers that are exempt from Permit to Construct requirements.

BOILER (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS

5. Type of Request: ☐ New Unit ☐ Unpermitted Existing Unit ☒ Modification to a Unit with Permit #:027-00010		
6. Use of Boiler: ☒ % Used For Process ☐ % Used For Space Heat ☒ % Used For Generating Electricity ☐ Other:		
7. Boiler ID Number: S-B2	8. Rated Capacity: ☒ 126 Million British Thermal Units Per Hour (MMBtu/hr) ☒ 105 1,000 Pounds Steam Per Hour (1,000 lb steam/hr)	
9. Construction Date: 1942	10. Manufacturer: Babcock & Wilcox	11. Model:
12. Date of Modification (if applicable): None	13. Serial Number (if available): None	14. Control Device (if any): None for nat. gas **Note: Attach applicable control equipment form(s)**

FUEL DESCRIPTION AND SPECIFICATIONS

15. Fuel Type	☐ Diesel Fuel (#) (gal/hr)	☒ Natural Gas (cf/hr)	☐ Coal (unit: /hr)	☐ Other Fuels (unit: /hr)
16. Full Load Consumption Rate		123000		
17. Actual Consumption Rate		111000		
18. Fuel Heat Content (Btu/unit, LHV)		1028		
19. Sulfur Content wt%		Negligible		
20. Ash Content wt%		N/A		

STEAM DESCRIPTION AND SPECIFICATIONS

21. Steam Heat Content	NA	NA		
22. Steam Temperature (^{o}F)	N/A	N/A		
23. Steam Pressure (psi)	N/A	N/A		
24 Steam Type	N/A	N/A	☐ Saturated ☐ Superheated	☐ Saturated ☐ Superheated

OPERATING LIMITS & SCHEDULE

25. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):	None
26. Operating Schedule (hours/day, months/year, etc.):	24h/d, 12mo/y
27. NSPS Applicability: ☐ Yes ☒ No	If Yes, which subpart:

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

AIR PERMIT APPLICATION

Revision 6
10/7/09

For each box in the table below, CTRL+click on the blue underlined text for instructions and information.

IDENTIFICATION	
1. Company Name: The Amalgamated Sugar Co. LLC	2. Facility Name: Nampa Facility
3. Brief Project Description: No. 1 & 2 B&W Boilers Natural Gas Only Project	

APPLICABILITY DETERMINATION	
4. List applicable subparts of the New Source Performance Standards (NSPS) (40 CFR part 60). Examples of NSPS affected emissions units include internal combustion engines, boilers, turbines, etc. The applicant must thoroughly review the list of affected emissions units.	List of applicable subpart(s): ☑ Not Applicable
5. List applicable subpart(s) of the National Emission Standards for Hazardous Air Pollutants (NESHAP) found in 40 CFR part 61 and 40 CFR part 63. Examples of affected emission units include solvent cleaning operations, industrial cooling towers, paint stripping and miscellaneous surface coating. EPA has a web page dedicated to NESHAP that should be useful to applicants.	List of applicable subpart(s): 40 CFR Part 63 Subpart DDDDD NESHAPs for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers & Process Heaters ☐ Not Applicable
6. For each subpart identified above, conduct a complete a regulatory analysis using the instructions and referencing the example provided on the following pages. **Note** - Regulatory reviews must be submitted with sufficient detail so that DEQ can verify applicability and document in legal terms why the regulation applies. Regulatory reviews that are submitted with insufficient detail will be determined incomplete.	☑ A detailed regulatory review is provided (Follow instructions and example). ☐ DEQ has already been provided a detailed regulatory review. Give a reference to the document including the date.

No. 1 & No. 2 B&W Boilers Natural Gas Firing Only Project
Nampa Facility

PROJECTED ACTUAL EMISSIONS *or* PTE FOR PROJECTED ACTUAL EMISSIONS

Emissions Unit	PM[a]	SO_2	NO_x	CO	VOC	LEAD	SULFURIC ACID
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Point Sources							
B&W Boilers - Natural Gas Firing	12.5	0.66	348	27.6	6.07	5.09E-04	0
Total Projected Actual Emissions	12.5	0.66	348	27.6	6.07		

BASELINE ACTUAL EMISSIONS

Emissions Unit	PM[a]	SO_2	NO_x	CO	VOC	LEAD	SULFURIC ACID
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Point Sources							
No. 1 B&W Boiler - Coal Firing	9.1	339.2	209	28	0.82	5.60E-03	4.55
No. 1 B&W Boiler - Coal Firing	10.3	382.9	236	31	0.93	5.60E-03	4.55
Total Baseline Actual Emissions	19.4	722.1	445	59	1.75	0.0112	9.1

COMPARISON OF THE PROJECT EMISSIONS INCREASE TO THE SIGNIFICANT EMISSIONS RATE THRESHOLDS

Emissions Unit	PM[a]	SO_2	NO_x	CO	VOC	LEAD	SULFURIC ACID
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Project Emissions Increase	-6.9	-721.44	-97	-31.4	4.32	-1.07E-02	-9.1
PSD Significance Emission Rate (SER) *See 40 CFR 52.21(b)(23)*	15	40	40	100	40	0.6	7
Does the Project Emissions Increase Exceed the Significant Emissions Rate Threshold?	No	No	No	No	No	No	No

[a] PM, PM10, PM2.5

PROJECTED ACTUAL EMISSIONS *or* PTE FOR PROJECTED ACTUAL EMISSIONS

Emissions Unit	CO_2	CH_4	N_20	CO_2e
	T/yr	T/yr	T/yr	T/yr
Point Sources				
B&W Boiler - Natural Gas Firing	133371	2.6	0.26	133512
Total Projected Actual Emissions	133371	2.6	0.26	133512

BASELINE ACTUAL EMISSIONS

Emissions Unit	CO_2	CH_4	N_20	CO_2e
	T/yr	T/yr	T/yr	T/yr
Point Sources				
No. 1 B&W Boiler - Coal Firing	50953	5.7	0.83	51342
No. 1 B&W Boiler - Coal Firing	57685	6.4	0.94	58124
Total Baseline Actual Emissions	108638	12.1	1.77	109466

COMPARISON OF THE PROJECT EMISSIONS INCREASE TO THE SIGNIFICANT EMISSIONS RATE THRESHOLDS

Emissions Unit	CO_2	CH_4	N_20	CO_2e
	T/yr	T/yr	T/yr	T/yr
Project Emissions Increase	24733	-9.5	-1.51	24046
PSD Significance Emission Rate (SER) *See 40 CFR 52.21(b)(23)*	NA	NA	NA	75000
Does the Project Emissions Increase Exceed the Significant Emissions Rate Threshold?	NA	NA	NA	No

[a] PM, PM10, PM2.5

PRE- AND POST PROJECT NON-CARCINOGENIC TAP EMISSIONS SUMMARY
POTENTIAL TO EMIT
No. 1 & No. 2 B & W Boilers Natural Gas Only Project
Nampa Facility

Non-Carcinogenic Toxic Air Pollutants (sum of all emissions)	Pre-Project [a] 24-hour Average Emissions Rates for Units at the Facility (lb/h)	Post-Project [b] 24-hour Average Emissions Rates for Units at the Facility (lb/h)	Change in 24-hour Average Emissions Rates for Units at the Facility (lb/h)	Non-Carcinogenic Screening Emission Level (lb/h)	Exceeds Screening Level? (Y/N)
Acetophenone	2.08E-04		-2.08E-04	none	NO
Acrolein	4.02E-03		-4.02E-03	1.70E-02	NO
Antimony	2.50E-04		-2.50E-04	3.30E-02	NO
Barium	5.34E-01	1.18E-03	-5.33E-01	3.30E-02	NO
Benzyl Chloride	9.71E-03		-9.71E-03	none	NO
Carbon Disulfide	1.80E-03		-1.80E-03	2.00E+00	NO
2-chloroacetophenone	9.71E-05		-9.71E-05	2.10E-02	NO
Chlorobenzene	3.05E-04		-3.05E-04	2.33E+01	NO
Chromium (total)	3.99E-03	3.77E-04	-3.61E-03	3.30E-02	NO
Cobalt	1.41E-03	2.26E-05	-1.39E-03	3.30E-03	NO
Cumene	7.36E-05		-7.36E-05	1.63E+01	NO
Cyanide	3.47E-02		-3.47E-02	3.33E-01	NO
Dichlorobenzene	3.23E-04	3.23E-04	0.00E+00	3.00E+01	NO
2,4-Dinitrotoluene	3.89E-06		-3.89E-06	none	NO
Dimethyl Sulfate	6.66E-04		-6.66E-04	none	NO
Ethyl Benzene	1.30E-03		-1.30E-03	2.90E+01	NO
Ethyl Chloride	5.83E-04		-5.83E-04	1.76E+02	NO
Ehtylene Dichloride	5.55E-04		-5.55E-04	2.67E+00	NO
Fluorides, as F	8.33E-02		-8.33E-02	1.67E-01	NO
Hexane	4.86E-01	4.85E-01	-9.30E-04	1.20E+01	NO
Hydrogen Chloride	2.60E-01		-2.60E-01	5.00E-02	NO
Hydrogen Fluoride	9.77E-01		-9.77E-01	none	NO
Isophorone	8.05E-03		-8.05E-03	1.87E+00	NO
Lead	5.96E-03	1.35E-04	-5.83E-03	none	NO
Magnesium	1.53E-01		-1.53E-01	6.67E-01	NO
Manganese	6.90E-03	1.02E-04	-6.80E-03	3.33E-01	NO
Mercury	1.22E-03	7.00E-05	-1.15E-03	none	NO
Methyl Bromide	2.22E-03		-2.22E-03	1.27E+00	NO
Methyl Chloride	7.36E-03		-7.36E-03	6.87E+00	NO
Methyl Ethyl Ketone	5.41E-03		-5.41E-03	3.93E+01	NO
Methyl Methacylate	2.78E-04		-2.78E-04	2.73E+01	NO
Methyl Tert Butyl Ether	4.86E-04		-4.86E-04	none	NO
Napthalene	0.00E+00		0.00E+00	3.33E+00	NO
Pentane	7.00E-01	7.00E-01	0.00E+00	1.18E+02	NO
Phenol	2.22E-04		-2.22E-04	1.27E+00	NO
Propionaldehyde	5.27E-03		-5.27E-03	2.87E-02	NO
Selenium	1.80E-02	6.46E-06	-1.80E-02	1.30E-02	NO
Styrene	3.47E-04		-3.47E-04	6.67E+00	NO
Sulfuric Acid	4.77E+00		-4.77E+00		NO
Toluene	4.25E-03	9.15E-04	-3.33E-03	2.50E+01	NO
Xylene (total)	5.13E-04		-5.13E-04	2.90E+01	NO
Vinyl Acetate	1.05E-04		-1.05E-04	none	NO

[a] Coal Fired

[b] Natural Gas Fired

PRE- AND POST PROJECT CARCINOGENIC TAP EMISSIONS SUMMARY
POTENTIAL TO EMIT

Carcinogenic Toxic Air Pollutants (sum of all emissions)	Pre-Project [a] 24-hour Average Emissions Rates for Units at the Facility (lb/h)	Post-Project [b] 24-hour Average Emissions Rates for Units at the Facility (lb/h)	Change in 24-hour Average Emissions Rates for Units at the Facility (lb/h)	Carcinogenic Screening Emission Level (lb/h)	Exceeds Screening Level? (Y/N)
Acetaldehyde	7.91E-03		-7.91E-03	3.00E-03	NO
Arsenic Compounds	5.74E-03	5.38E-05	-5.69E-03	1.50E-06	NO
Benzene	1.86E-02	5.65E-04	-1.80E-02	8.00E-04	NO
Beryllium Compounds	2.95E-04	3.23E-06	-2.91E-04	2.80E-05	NO
Bis (2-ethylhexyl) phthalate	1.01E-03		-1.01E-03	2.80E-02	NO
Cadmium Compounds	1.00E-03	2.96E-04	-7.08E-04	3.70E-06	NO
Chloroform	8.19E-04		-8.19E-04	2.80E-04	NO
Chromium 6+ Compounds	1.47E-03	3.77E-04	-1.10E-03	5.60E-07	NO
Ethylene Dibromide	1.67E-05		-1.67E-05	3.00E-05	NO
Formaldehyde	2.35E-02	2.02E-02	-3.33E-03	5.10E-04	NO
Methyl Hydrazine	2.36E-03		-2.36E-03	2.20E-05	NO
Methylene Chloride	4.02E-03		-4.02E-03	1.60E-03	NO
Nickel	4.45E-03	5.65E-04	-3.89E-03	2.70E-05	NO.
PAHs	2.89E-04		-2.89E-04	9.10E-05	NO
POM	2.24E-05	2.24E-05	0.00E+00	9.10E-05	NO
Tetrachloroethylene	5.97E-04		-5.97E-04	1.30E-02	NO
1,1,1 - Trichloroethane	2.78E-04		-2.78E-04	4.20E-04	NO

[a] Coal Fired

[b] Natural Gas Fired

SUMMARY OF FACILITY-WIDE PROJECTED EMISSIONS
Nampa Facility

Emissions Unit	PM[a]	SO_2	NO_x	CO	VOC	CO_2	CH_4	N_2O	CO_2e
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Point Sources									
B&W Boiler No. 1	12.0	0.3	154.5	46	3	67146	1.3	0.13	67126
B&W Boiler No. 2	12.0	0.3	154.5	46	3	67146	1.3	0.13	67216
Riley Boiler	51.3	1600	611.6	129.9	8.7	273762	28.6	4.1	275726
Union Boiler	6.8	0.2	31.5	28.9	1.7	38369	0.74	0.074	38410
South Pulp Dryer	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Center Pulp Dryer	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
North Pulp Dryer	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pellet Cooler Baghouse	3.5								
Lime Kiln A	1.5	0.56	10.52	928.7	0.74	7858	0.88	0.13	7918
Lime Kiln B	1.75	0.65	12.22	1078.2	0.86	9093	1.0	0.15	9163
Lime Kiln Material Handling	3.45								
A & B Process Slakers	6.10								
Drying Granulator	5.00								
#1 Cooling Granulator	1.30								
#2 Cooling Granulator	1.30								
Sugar Handling(Process)	1.20								
Sugar Handling(Specialties)	0.60								
Sugar Handling(Packaging Line)	0.90								
Main Mill					59.2				
Sulfur Stoves		14.2							
Fugitives									
Coal Unloading Railcar @Dryer	0								
Pulp&PelletStorage and Loadout	0.0147								
Coal Unloading (Railcar)	0.0031								
Coal Storage/Loading	1.79								
Beet Hauling	1.21								
Vehicle Traffic Unpaved Roads	0.49								
Lime Rock Handling	0.68								
Coke Handling	0.2								
Totals	113.1	1616.2	974.84	2257.7	77.2	463374	33.82	4.714	465559

Projected HAPs
Emissions Summary
Nampa Facility

HAP Pollutants	PTE (t/y)
Acetaldehyde	2.50
Acrolein	0.07
Formaldehyde	0.16
Methanol	46.63
Arsenic	0.03
Benzene	0.07
Beryllium	0.00
Cadmium	0.05
Chromium	0.02
Cyanide	0.19
Hydrochloric Acid	1.01
Hydrogen Fluoride	3.80
Lead	0.03
Manganese	0.04
Mercury	0.00
Nickel	0.02
Selenium	0.10
Toluene	0.02
Xylenes	0.00
PAH and other HAPs	0.20
Total	54.96

Section 2
Project & Facility Descriptions
No.1 & No.2 B&W Boilers Natural Gas Only Project
Nampa Facility

PROJECT DESCRIPTION

The primary objective of this permit application is to obtain a permit for natural gas firing exclusively in the No.1 and No.2 B&W boilers and eliminate coal as a fuel source by these boilers. As discussed in Section 4 of the application, firing natural gas only is an acceptable alternative for demonstrating compliance with Industrial Boiler Maximum Allowable Control Technology (MACT) and the Tier II Operating Permit Best Available Retrofit Technology (BART) requirements (No. T2-2009.0105). In addition, this application has also been prepared to address PTC requirements provided in Compliance Schedule 14 of Tier I Operating Permit No. T1-050020.

FACILITY DESCRIPTION

The Amalgamated Sugar Company, LLC (TASCO) Nampa, Idaho Facility (hereinafter, the "Nampa facility" or "facility") is a sugar beet processing facility which produces refined granulated sugar and other related products for commercial and retail markets. The facility was constructed in 1942 and is currently owned by the Snake River Sugar Company, a cooperative of beet growers that cultivate and supply beets each year for processing at the plant. The Nampa facility is located 2 miles north of downtown Nampa, Idaho at the corner of Northside Boulevard and Karcher Road. The annual beet crop is harvested and processed each year during fall and winter. Following the beet processing "campaign", "thick juice" is processed for the remainder of the year into granulated sugar. Production days and product quantities are dependent on size and quality of the beet crop which vary each year. Factors which affect the size of the beet crop include growing season ambient temperatures, weather conditions, and availability of water.

There are three modes of operation at the Nampa facility. During the beet campaign, the entire plant is operated at full capacity (both beet end and sugar end equipment) in an effort to process beets as quickly as possible to minimize sugar losses which occur as beets deteriorate in storage piles. Following the beet campaign, operations continue with either a juice run or a separator only run. During the juice run, the sugar end equipment is operated to process thick juice from storage or juice transferred from other facilities. The separator system is used to desugarize molasses using a chromatographic separator. The separator is operated nearly year round during beet campaign, juice run and in a third mode referred to as separator only operation. During the juice run and separator only runs, a significant portion of the facility is not operated.

Attachment A provides descriptions of the processes and emissions sources at the facility. In general, the facility can be divided into the beet end and sugar end processes. The principal emissions sources at the facility are 4 fossil fuel fired steam boilers and 2 lime kilns.

BOILER HOUSE & STEAM PRODUCTION PROCESS

The boiler house provides steam primarily for evaporation processes within the main mill and electricity generation for onsite uses. The boiler house consists of the No. 1 and No. 2 Babcock &

Wilcox, Riley and Union boilers. All boilers except the Union boiler are dual fired (coal/gas) units. The Union boiler fires natural gas only. When firing coal, emissions from the Riley and two B&W boilers are controlled by baghouses. High pressure (400 psig) and some low pressure (200 psig) steam is used to dry beet pulp in the state-of- the-art steam dryer system. Steam recovered from the steam dryer is the primary source of energy in the main mill for process applications. Additionally, electricity is co-generated by first passing high pressure steam through turbine generators. From the turbines, lower pressure steam is used for other process demands. Table 1 provides a summary description of each boiler at the Nampa facility.

Table 1. EXISTING BOILERS – NAMPA FACILITY

Parameters	No.1 B&W Boiler	No.2 B&W Boiler	Riley	Union[a]
Fuel	Coal/Gas	Coal/Gas	Coal/Gas	Gas
Steam Type	Saturated	Saturated	Superheated	Saturated
Maximum Capacity (Klbs/h)	105	105	250 (gas) 250 (coal)	200
Pressure (psig)	200	200	400	200
Temperature (°F)	450	450	625	400
Emissions Controls	Baghouse[b]	Baghouse[b]	Baghouse[b]	None

[a] Backup boiler
[b] Coal-firing only

The Nampa facility will be decommissioning the B&W boilers coal-firing systems and associated equipment and firing the natural gas burners only. The coal pulverizers and burners will no longer operate and the coal feed system will be dismantled to prevent any future firing using coal. For natural gas firing, exhaust gases from the B&W boilers will pass through the preheater, bypass the baghouse and will exit through the existing stack.

Attachment A Process Descriptions & Emissions Sources

The Amalgamated Sugar Co. LLC Nampa, Idaho Facility

The Amalgamated Sugar Company, LLC (TASCO) Nampa, Idaho Facility (hereinafter, the "Nampa facility" or "facility") is a sugar beet processing facility located about two miles north of downtown Nampa, Idaho in the Treasure Valley. The Treasure Valley is a wide plain created by the Snake and Boise Rivers between the Owyhee and Boise Mountains. The Nampa facility produces granulated sugar, dried pulp, molasses, betaine, and concentrated separator byproduct (CSB).

Process Descriptions

Modes of Operation – There are three modes of operation at the Nampa facility. During the beet campaign, the entire plant is operated at full capacity (both beet end and sugar end equipment) in an effort to process beets as quickly as possible to minimize sugar losses which occur as beets deteriorate in storage piles. Following the beet campaign, operations continue with either the juice run or a separator only run. During the juice run, the sugar end equipment is operated to process thick juice from storage or juice transferred from other facilities. The separator system is used to desugarize molasses using a chromatographic separator. The separator is operated nearly year round during beet campaign and juice run and in a third mode referred to as separator only operation. During the juice run and separator only runs, a significant portion of the facility is not operated.

As discussed below, the facility can be divided into beet end processing and sugar end processing. Generalized process flow diagrams of Nampa facility operations are presented in Figures 2-1 and 2-2 located at the end of this section (Section 2.0).

Beet End Processes - Mechanically harvested sugar beets are delivered to remote piling grounds near the point of harvest. At the piling grounds, the beets are partially cleaned using beet pilers that remove loose dirt by passing the beets over rolls. The pilers then stack the beets onto storage piles. Beets are shipped from off-site storage piling grounds to the facility using trucks or rail cars. Beets are dumped by rail cars or trucks into wet hoppers feeding a flume. The flumes use water to transport and clean the beets. The flumes transport the beets to the beet feeder, which regulates the flow of beets into the process. From the feeder, the flumes carry the beets through several cleaning devices that include rock catchers, sand separators, water sprays and weed catchers. After cleaning, the beets are separated from the water and are transported by a chain and bucket elevator to the processing operations. The sugar beet processing operations comprise several steps including slicing, diffusion, juice purification, evaporation, crystallization, dried pulp production, and sugar recovery from molasses.

Prior to the diffusion process, the cleaned and washed beets are sliced into long thin strips called cossettes. The cossettes are conveyed to two continuous vertical diffusers, in which hot water is used to extract sucrose from the cossettes. Within the diffuser the cossettes are conveyed upward as hot water is introduced into the top of the diffuser. The hot water flows countercurrent to the cossettes. The temperature within the diffusion process is typically maintained between 50°C and 80°C (122°F and 176°F). This temperature is dependent on several factors, including the denaturation temperature of the cossettes, the thermal behavior of the beet cell wall, potential enzymatic reactions, bacterial activity, and pressability of the beet pulp. Disinfectants, such as ammonium bisulfite is sometimes added to the diffuser to control bacterial growth. The sugar enriched water that flows from the outlet of the diffuser is called raw juice and contains between 13 and 18 percent sugar. This raw juice proceeds to the juice purification operations. The processed cossettes, or pulp, from the diffuser is pressed to remove water and then conveyed to the dried pulp production operations.

In the juice purification stage, non-sucrose impurities in the raw juice are removed so that the pure sucrose can be crystallized. First, the juice passes through screens to remove any small cossette particles. The mixture is heated to 80°C to 85°C (176°F to 185°F) and proceeds to liming tanks, where milk of lime [$Ca(OH)_2$] is added to the mixture to react, absorb or adhere to impurities. The juice is then sent to the first carbonation tanks where carbon dioxide (CO_2) gas is bubbled through the mixture to precipitate the lime and impurities from the juice as insoluble calcium carbonate. Lime kilns are used to produce the lime and CO_2 used in the juice purification process. The lime is converted to milk of lime in lime slakers.

The small insoluble calcium carbonate crystals (produced during carbonation) settle out in a clarifier after which the juice is again treated with CO_2 (in the second set of carbonation tanks) to remove the remaining lime. The pH of the juice is lowered during this second carbonation, causing large, easily filterable, calcium carbonate crystals to form. After filtration, the juice is softened in an ion exchange process. Then, a small amount of SO_2 is added to the juice to inhibit reactions that lead to darkening of the juice. Following the addition of SO_2, the juice (known as thin juice) proceeds to the evaporators.

The evaporation process, which increases the sucrose concentration in the juice by removing water, is performed in a series of multiple effect evaporators. Steam produced by onsite boilers is used to heat the first evaporator, and the steam vapor from the water evaporated in the first evaporator is used to heat the second evaporator. This transfer of heat continues through the five effect evaporators, and as the temperature decreases from evaporator to evaporator, the pressure inside each evaporator is also decreased, allowing the juice to boil at the lower temperatures provided in each subsequent evaporator. Some steam vapor is released from the first four evaporators, and this steam vapor is used as a heat source for various process heaters throughout the plant. After evaporation, the percentage of sucrose in the "thick juice" is approximately 60 percent. The "thick juice" is combined with crystalline sugars, produced in an ancillary process, and dissolved in the high melter. This mixture is then filtered, yielding a clear liquid known as standard liquor, which proceeds to the crystallization operation.

Wet pulp from the diffusion process is another product of the beet end process. Some of the wet pulp is sold as animal feed directly. However, most of the wet pulp is pressed to reduce the moisture content from about 90 percent to about 75 percent. The water removed by the pulp presses is collected and used as diffusion water. After pressing, the pulp may be sold as pressed pulp animal feed or sent to the dryer. The pressed pulp is then dried to approximately 10% residue moisture in a state-of-the-art steam dryer. The steam dryer uses high pressure (400 psig) and low pressure (200 psig) steam from the facility boilers as the energy source. Molasses or molasses byproduct is added to the dried pulp and the resulting product is typically pelletized and is sold as animal feed. The remainder of the dried pulp is sold in an unpelletized form called "shreds".

Sugar End Processes – Sugar end processing involves the conversion of thick juice into refined granulated sugar. Sugar is crystallized by low temperature (relative to the boiling temperature at atmospheric pressure) boiling in vacuum pans until it becomes super-saturated. To begin crystal formation, the liquor is "seeded" with finely milled sugar. The seed crystals are carefully grown through control of the vacuum, temperature, feed liquor additions and steam. When the crystals reach the desired size, the mixture of liquor and crystals, known as massecuite or fillmass, is discharged to the mixer. From the mixer, the massecuite is poured into high-speed centrifugals, in which the liquid is centrifuged into the outer shell, and the crystals are left in the inner centrifugal basket. The sugar crystals in the centrifugal are then washed with pure hot water and are sent to the granulator, which is a rotary drum dryer, and then to the cooler. After cooling, the sugar is stored in large silos for future packaging and bulk shipments.

The liquid that was separated from the sugar crystals in the centrifugals is called syrup. This syrup serves as feed liquor for the "second boiling" and is introduced back into a second set of vacuum pans. The crystallization/centrifugation process is repeated once again, resulting in the production of molasses. The sugar crystals from the second and third boilings are recycled to the production process through remelting in the high melter with thick juice to produce standard liquor.

The molasses produced in the third boiling step can be used as an additive to dried pulp. This molasses can also be further desugarized using the separator process. The products of the separator process are "extract" (the high sugar fraction) and "CSB-concentrated separator by-product (the low sugar fraction)"and betaine. The extract, after being concentrated using multiple effect evaporation, can be stored in tanks or immediately processed in the sugar end, like thick juice. The CSB is also concentrated using multiple effect evaporation and is used as livestock feed in either a liquid form or added to pulp. The betaine is sold as a liquid product that is used in the animal feed industry as a food additive.

Emission Sources

The primary emission sources at the facility are four fossil-fueled steam boilers and two lime kilns. These emission sources and other minor emission sources at the Nampa facility are discussed below:

<u>Steam Boiler System</u> – The steam boiler system consists of four boilers that provide steam for sugar refinement processes in the main mill. The boiler complex consists of two Babcock & Wilcox boilers, fueled by either coal or natural gas and controlled with a baghouse, a Riley boiler, fueled by coal or natural gas and controlled with a baghouse, and one Union unit, fired by natural gas. The boiler house also includes coal handling. The predominate feature of the facility's energy management system is the combined heat/power (CHP) utilization of steam. The facility co-generates electricity using steam/turbine generators and beet pulp is dried in a steam dryer using steam. Both processes, convert high pressure steam from the boilers to low pressure steam for further use in the process (see Figure 2-3 below).

<u>Lime Kiln and CO_2 Production</u> – The lime kiln building consists of two vertical lime kilns that convert lime rock into calcium oxide (CaO) rocks and carbon dioxide (CO_2) gas; a crusher to reduce the CaO rocks in size; two slakers to produce milk of lime ($Ca(OH)_2$) from the crushed CaO and thin juice; and material handling equipment of coke, lime rock, and CaO (S-K3).

The CO_2 generated in the lime kilns is dried, compressed, and used in the first and second carbonation tanks that are part of the sugar purification process. Lime kilns combustion gases that are not bubbled through the carbonation tanks are controlled with a baghouse. The crusher and various emission points from coke and CaO handling are controlled with a baghouse. The process slaker emissions are controlled with a wet scrubber.

<u>Dried Pulp Pelletizing</u> – Dried pulp leaving the pulp dryer can be mixed with CSB or molasses and pelletized with six pellet mills. The six pellet mill coolers emissions are controlled with a single pellet mill baghouse.

<u>Sugar Warehouse and Shipping</u> – The warehouse/shipping area contains twelve sugar silos; sugar classification units; metal detectors; railcar loading and unloading areas; and bulk loading scales. These sugar product transfer points are controlled with baghouses. Separate housekeeping vacuums also utilize small baghouses. Baghouses are also used to control sugar dust from the drying and cooling granulators.

<u>Fugitive Emission Sources</u> – The Nampa facility has several fugitive dust source groups. These sources and emissions are presented in Section 4.0.

Process and Emissions Flow Diagrams – Please refer to the TASCO Nampa facility Tier I and Tier II operating permit applications on file with the Department for a complete set of process and emissions flow diagrams.

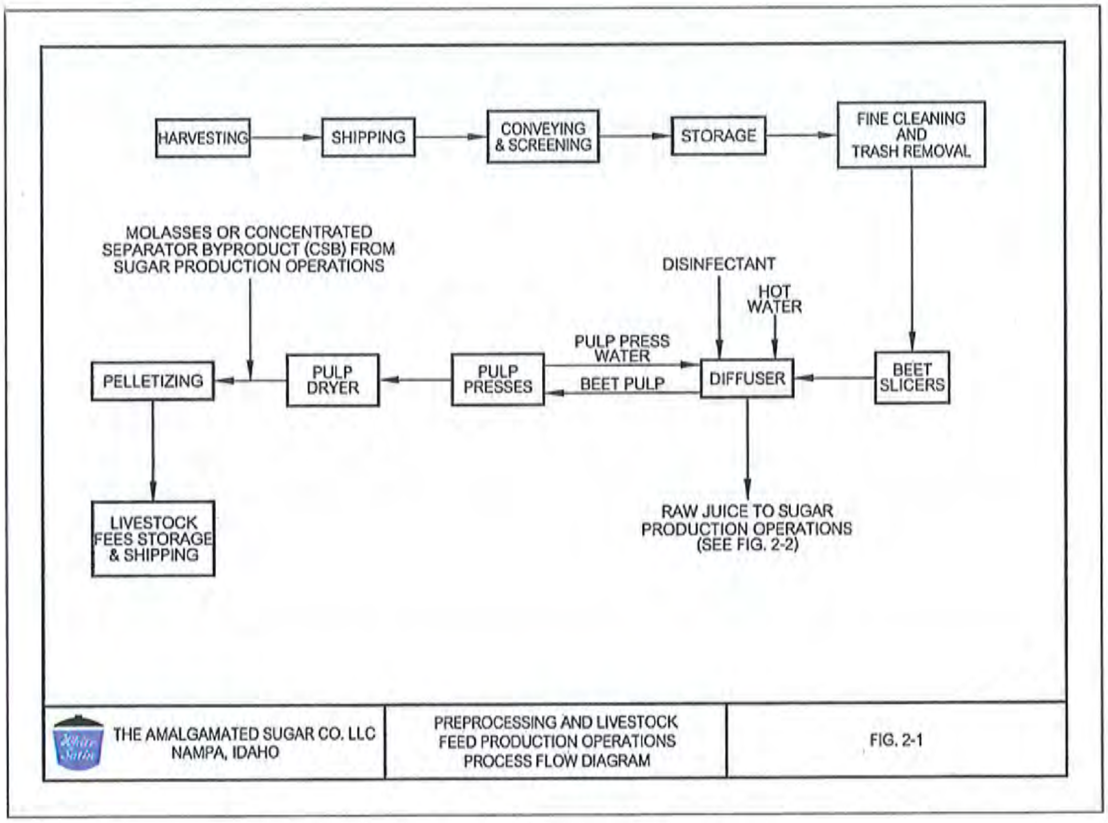


Figure 2-1. Process Flow Diagram – Preprocessing and Feed Production Operations

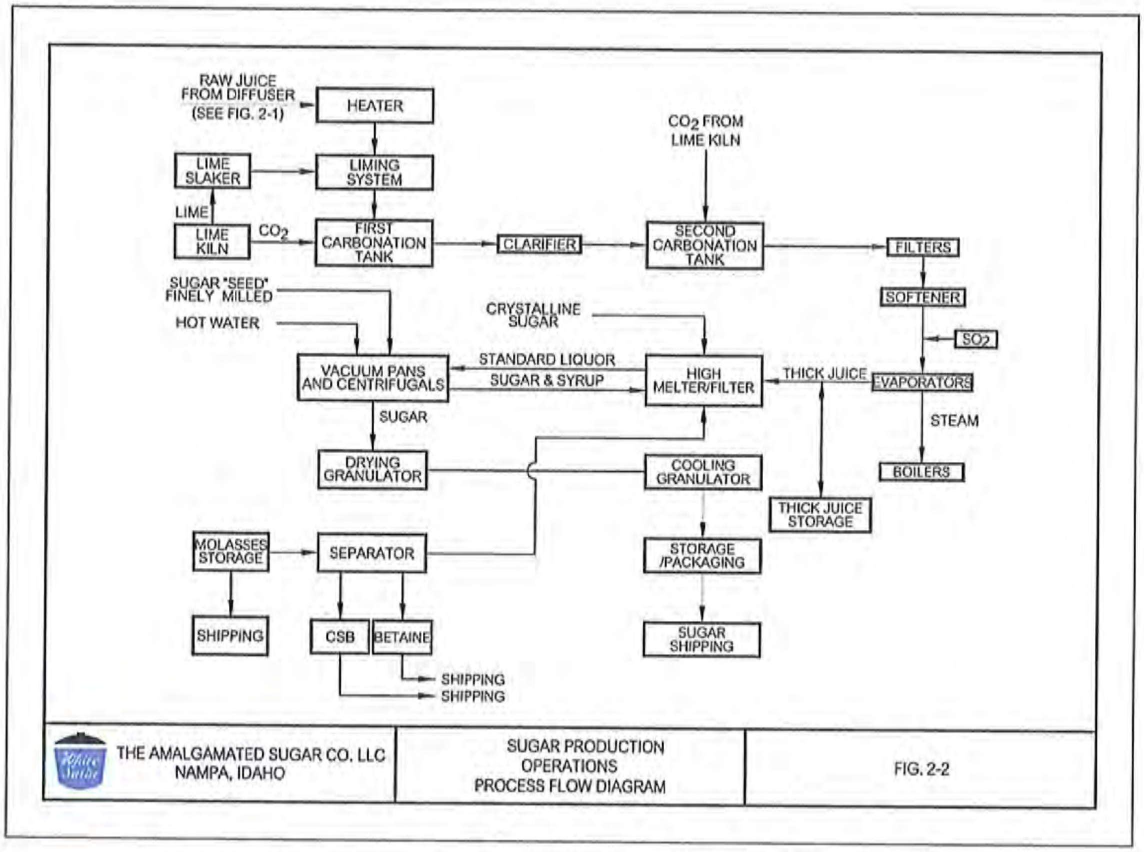


Figure 2-2. Process Flow Diagram – Sugar Production Operations

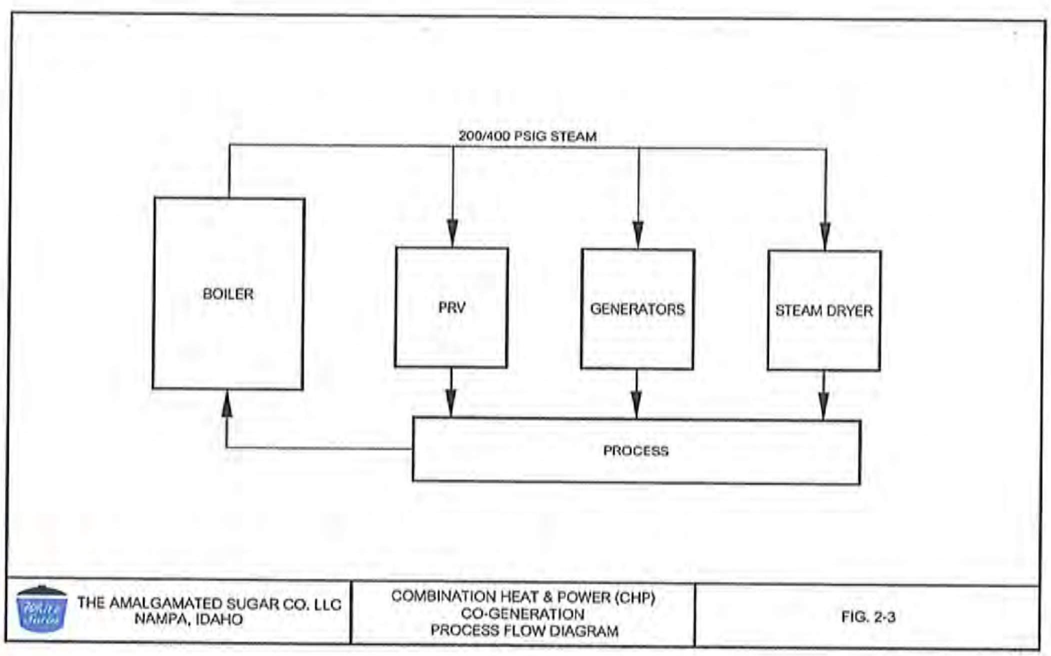


Figure 2-3. Steam Flow Diagram – Combined Heat Power (CHP)

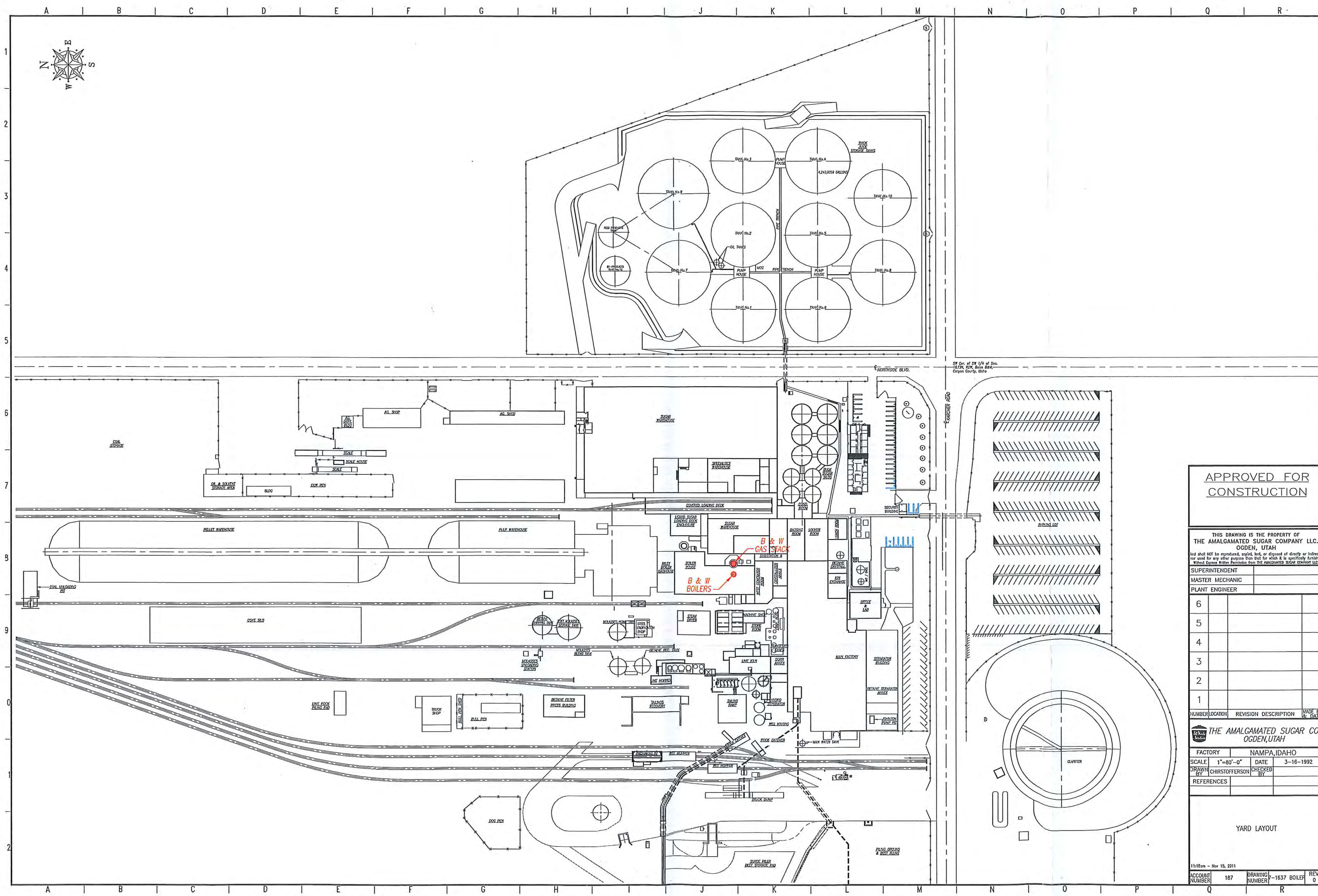
Section 3 – Factory Layout & Process Flow Diagrams

This section provides a general facility layout, location of the B&W boilers stack and process flow diagrams for the B&W boilers.

Figure 1 – Nampa Facility Layout
Figure 1 is a general layout of the facility and identifies the No. 1 and No. 2 B&W boilers.

Figure 2 – Stack Location
Figure 2 is a general plan view identifying the location of the No. 1 & No. 2 B&W boilers stack.

Figure 3 – Existing and Proposed B&W Exhaust Flow Diagrams
Figure 3 shows the process flow diagrams for the existing No. 1 & No. 2 B&W Boilers coal/gas firing systems and diagram for natural gas firing only.



B & W
GAS STACK
B & W
BOILERS
APPROVED FOR
CONSTRUCTION
THIS DRAWING IS THE PROPERTY OF
THE AMALGAMATED SUGAR COMPANY LLC.
OGDEN, UTAH
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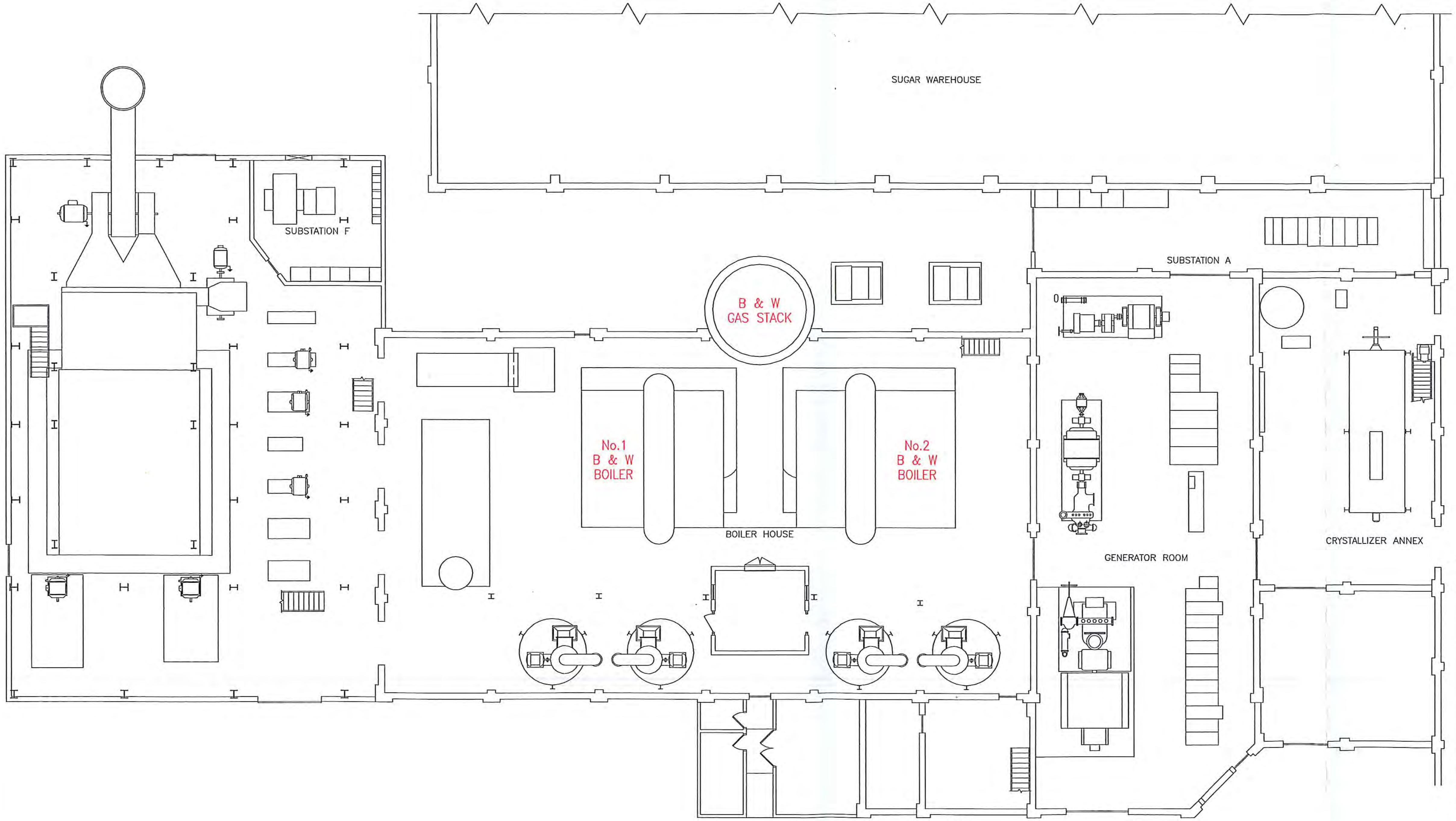
SUPERINTENDENT
MASTER MECHANIC
PLANT ENGINEER
6
5
4
3
2
1
NUMBER LOCATION REVISION DESCRIPTION MADE BY & DATE
THE AMALGAMATED SUGAR CO.
OGDEN,UTAH
FACTORY NAMPA,IDAHO
SCALE 1"=80'-0" DATE 3-16-1992
DRAWN BY CHIRSTOFFERSON CHECKED BY
REFERENCES
YARD LAYOUT
11:18am - Nov 15, 2011
ACCOUNT NUMBER 187 DRAWING NUMBER 7-1637 BOILER REV. 0



SUPERINTENDENT	
MASTER MECHANIC	
PLANT ENGINEER	

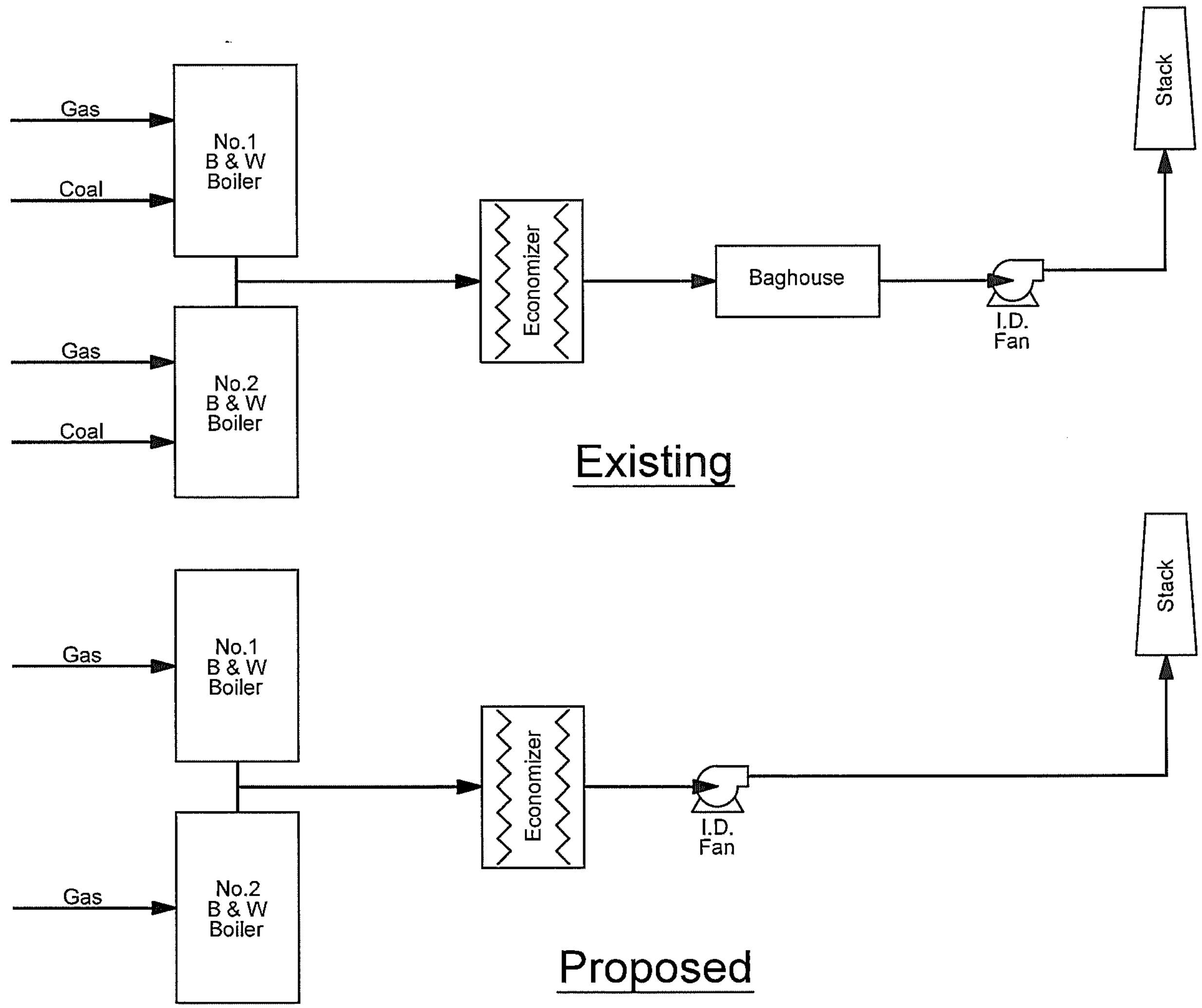
NUMBER	LOCATION	REVISION DESCRIPTION	MADE BY & DATE
6			
5			
4			
3			
2			
1			

THE AMALGAMATED SUGAR CO.
OGDEN, UTAH

FACTORY	NAMPA, IDAHO		
SCALE	*NONE*	DATE	*SEPT. 13, 2001*
DRAWN BY	*R.RENO*	CHECKED BY	
REFERENCES			

1ST FLOOR
BOILER HOUSE, GENERATOR ROOM,
AND SUBSTATION A

ACCOUNT NUMBER	DRAWING NUMBER	REV.
181C & 207	*7–3149 GLENN*	*0*



THE AMALGAMATED SUGAR CO.	No.1 & No.2 - B & W Boilers Natural Gas Only Project Process Flow Diagram
Factory: Nampa, Idaho	

Section 4
Regulatory Analysis & Emissions Evaluation

The first part of this section provides an analysis of air quality regulations which apply to firing natural gas only in the No. 1 & No. 2 B&W boilers at the Nampa facility. For this project, TASCO has conducted a detailed analysis of: 1) Tier I and Tier II Operating Permit requirements issued by the Idaho Department of Environmental Quality (IDEQ) and 2) Any other applicable Federal or Idaho emission standard requirements for the B&W boilers. In addition, an updated facility wide PTC evaluation is provided as required by Conditions 14.12 and 14.13 of the Tier I Operating Permit.

The second part of this section provides an evaluation of emissions changes associated with this project. Supporting documentation for the annual baseline emissions, future projected actual emissions and net emissions changes are provided in Section 5.

4.1 Existing Permits – Overview

IDEQ has issued three operating permits which are currently in effect for the Nampa facility. These permits are summarized below.

Tier I Operating Permit (Permit No. T1-050020. Issued 12/12/02. Modified/Amended 5/23/2006. Expired 12/12/2007.)[1]

The Tier I Permit establishes facility-wide requirements in accordance with the Idaho SIP and the Rules of the Control of Air Pollution in Idaho (IDAPA 58.01.01.300-386). Applicable Conditions of previously issued permits were also incorporated into the Tier I Permit including the 2002 Tier II Permit Requirements described below. A renewal application for this permit was submitted to IDEQ on June 29, 2007.

Tier II Operating Permit – Northern Ada County PM10 SIP Control Strategy (Permit No. T2 – 050021. Issued 9/30/2002. Modified 2006. Expired 9/30/2007.)

This 2002 Tier II permit was issued to the Nampa facility in support of the Northern Ada County PM_{10} SIP control strategy. The permit established enforceable PM_{10} and CO emission limits for all emissions sources. The permit also included a list of emission reduction projects. These projects which were completed between 2003 and 2007 are as follows: 1) Installation of pellet mill baghouse (2003); 2) Flue gas from Riley boiler was merged into the B&W boiler stack (2003) and; 3) Installation of pulp steam dryer system (2007) which replaced 3 coal-fired pulp dryers. A renewal application for this permit was submitted to IDEQ on April 11, 2007.

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[1] Until the issuance of the Tier I and Tier II Operating Permits in 2002, the Nampa facility operated in accordance with the 1981 Operating Permit (No. 13-0400-0010-01). The 1981 permit was renewed in 1984 (No. 0400-0010). Previous correspondence regarding facility operations was prepared in accordance with the 1981 and 1984 permits.

Tier II Operating Permit – Riley Boiler BART Requirements (Permit No. T2-2009.0105 Project No. 61426. Issued 9/19/2014. Expires 12/23/2016.)

This permit established Best Available Retrofit Technology (BART) requirements for the Riley boiler and B&W boilers in accordance with 40 CFR 51.308 (e) and IDAPA 58.01.01.668. Although not directly regulated as BART sources the B&W boilers were included in the compliance strategy for the Riley boiler. These boiler emissions reduction measures were required by IDEQ in order to address Protection of Visibility requirements (40 CFR 51, Subpart P). The permit focuses on NO_x and PM_{10} emissions reduction measures from the Riley and/or B&W boilers as follows: 1) Installation of low NO_x burners (LNB's) and/or; 2) Utilizing natural gas in place of coal.

4.2 Air Quality Regulatory Requirements – No. 1 & No. 2 B&W Boilers

This section provides a discussion of the air quality regulatory requirements which apply to the No. 1 and No. 2 B&W boilers. The Tier I Operating Permit includes requirements which were in effect when the permit was issued in 2002. More recent requirements including BART and Boiler MACT are also discussed.

4.2.1 Tier I Operating Permit

The No. 1 and No. 2 B&W boilers, which were installed in 1942, are regulated sources covered under the Tier I Operating Permit. Each boiler has a rated capacity of 105 Klbs steam per hour. These boilers (ID No's. S-B1 and S-B2) are permitted to fire pulverized coal and/or natural gas. For coal firing, a baghouse (A-B1/2) is required to be operated. For natural gas firing the baghouse is bypassed. Exhaust gases from the B&W boilers are vented to a 200 foot stack (S-B1/2).

A majority of the Tier I Operating Permit requirements focus on coal firing as follows:

- Particulate emissions limits and performance testing
- Coal firing rates and boiler steam production
- Baghouse O&M Manuals and pressure drop monitoring
- Visible emissions monitoring

In addition, the Tier I Permit also includes short-term (lb/h) and long-term (t/y) emissions limits for PM_{10} and CO, based upon the coal firing operating scenario at that time. These limits were included in the 2002 Tier II Permit and rolled into the Tier I Permit as an applicable requirement.

With the B&W boilers firing natural gas only some of the Tier I and underlying permit conditions will remain the same, however certain coal firing related permit conditions will become obsolete and can be removed. There will be no changes to the steam production maximum capacities of the boilers. When firing natural gas, PM_{10} and CO emissions will be well below the limits specified in Table 3-4 of the Tier I Permit.

4.2.2 Tier II BART Permit

Firing the No. 1 and No. 2 B&W boilers with natural gas is an approved option for ensuring compliance with the BART Tier II Permit. Supporting documentation for the natural gas firing option is provided in

Attachment B including Tier II Permit Condition 3.3 and IDEQ's September 17, 2014 letter which "clarifies Tier II Permit conditions pertaining to the B&W boilers". The compliance deadline for B&W's and Riley boilers emissions reduction is no later than July 22, 2016. As discussed below, the Nampa facility's commitment to fire natural gas only will occur no later than January 31, 2016.

4.2.3 Industrial Boiler NESHAP's/MACT

All boilers at the Nampa facility are subject to the requirements under 40 CFR Part 63 Subpart DDDDD (5D) or NESHAPS for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. These rules (commonly referred to as Boiler Maximum Achievable Control Technology (MACT)) were promulgated on March 21, 2011 with final changes published in the Federal Register on January 31, 2013. As provided to IDEQ in the Tier I Permit renewal application and the Initial Notification to EPA, the Nampa facility is categorized as a major HAP's source since estimated facility-wide emissions are greater than 10 tons per year of any single hazardous air pollutant (HAP) and 25 or more tons per year of any combination of HAP (see Section 5.5 for facility HAP's emissions estimates). The B&W boilers are industrial boilers as defined in 40 CFR 63.7575 and are subject to the rule under 63.7485. Boilers with heat input greater than 10 MMBtu/hr are categorized as large fuel boilers. For boilers firing coal, the deadline for compliance with applicable emissions standards is January 31, 2016.

By firing natural gas only in the B&W boilers, limited requirements of the Boiler MACT will apply. When fired with natural gas, the No. 1 & No. 2 B&W boilers will not be subject to any emission limits, and/or operating limits. In accordance with Subpart 5D, natural gas boilers are subject only to work practice standards including annual tune-ups and a onetime energy assessment. A tune-up of the natural gas burners will be required every 5 years as per 63.7540(a)(12) and Table 3 of the rule[2]. The first tune up for the B&W boilers was completed on September 14, 2015. The next tune up must be completed within 5 years when the B&W boilers are firing natural gas or by September 13, 2022. An energy assessment as defined in 63.7575 must be completed by a qualified energy assessor. The scope of the energy assessment is defined in Item 4 in Table 3 of Subpart 5D and includes an evaluation of the boiler efficiencies and potential facility-wide energy conservation measures. Based on an estimated combined total boiler heat input of ~ 4.0 T·Btu/y, 64 hours of onsite technical labor hours are required for this assessment.

4.2.4 Permit to Construct Applicability

Under IDAPA air quality rules a permit to construct is required for modification of a stationary source. The regulatory definition of Modification excludes "use of an alternative fuel…if the stationary source is specifically designed to accommodate such fuel…and use of such fuel…is not specifically prohibited by a permit." 58.01.01.006.68. The Nampa facility is capable of accommodating use of natural gas in the B&W boilers and such use is specifically allowed by a permit. Therefore, the proposed firing of natural gas only is not a modification that triggers PTC review. Nonetheless, in light of the permit history summarized above and the compliance obligations under MACT, BART and the Tier I permit, TASCO requests updates to applicable permits, as needed.

[2] The burner tune- up consists of inspecting the flame pattern and system controlling the air to fuel ratios. As needed, adjustments, cleaning or replacements are required in order to optimize CO and NO_x emissions.

4.3 Permit to Construct (PTC) Emissions Analysis – No. 1 & No. 2 B&W Boilers Natural Gas Firing

TASCO prepared two emissions analyses for the Department (boilers and facility-wide) to highlight the emissions reductions that will be achieved by TASCO's selection of natural gas as the exclusive fuel for the B&W boilers. Firing the B&W boilers with natural gas will significantly reduce emissions compared to coal firing. In order to quantify the emissions reductions, baseline versus projected actual emissions estimates have been calculated. Net emissions decreases for firing natural gas only were calculated based on PSD regulatory procedures for major modifications determinations[3].

Baseline actual emissions for calculating the emission change is defined in 40 CFR Part 52.21(b)(48)(ii). The baseline actual emissions are defined as the average rate in tons per year, at which the B&W boilers actually emitted the pollutant during a 24-month consecutive period during past 10 year period. The 24-month period selected for this analysis is the average for the 2006 and 2007 beet campaigns (including juice runs). During the 2006/2007 campaigns, 97% of the B&W boiler steam was produced using coal and 3% produced using natural gas. Projected actual emissions are based on the definition in 40 CFR 52.21(b)(41) and conservatively assume that the boilers operate for 8760 hours per year while firing natural gas. In other words, the future emissions were calculated as the boilers PTE. Actual operations will be far less than 8760 hours per year. Table 1 provides the emissions changes for firing natural gas exclusively and eliminating coal firing.

Table 1. Summary of No. 1 & No. 2 B&W Boiler Annual 2006/2007 Baseline Actual Emissions (BAE) vs. Projected Emissions[a]

Type of Emissions	PM[b] (t/y)	NO_x (t/y)	SO_2 (t/y)	CO (t/y)	VOC (t/y)	CO_2e (t/y)
Projected/Permitted	12.5	348	1.0	27.6	6.07	133,374
Baseline Actual	19.4	445	682	59.3	1.75	108,651
Net Change	-6.9	-98	-681	-31.7	4.3	24,722
PSD SER[c]	15	40	40	100	40	75,000
Significant	No	No	No	No	No	No

[a] Projected emissions assume permitted PTE or 8760 h/y
[b] PM, PM_{10}, $PM_{2.5}$
[c] Significant Emission Rate

As shown, significant decreases in criteria pollutants will occur from this project with the exception of a small increase in VOC's. Overall, criteria pollutant emissions are estimated to decrease by over 900 tons per year. Estimated CO_2e increases are only due to the permitting assumption that the B&W boiler will operate 8760 hours per year. Actual operations will be far less than 8760 hours per year. As a result, actual CO_2e will decrease when the B&W boiler fires natural gas only.

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[3] As per the PSD regulations, a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases: 1) A significant emissions increase and 2) A significant net emissions increase. The regulations specify a two part test to make this determination. The first test is to determine if the project will cause a significant emissions increase as specified in 52.21(a)(2)(iv)(b) through (f). The second test, if required, is used to determine if the project will cause a significant net emissions increase, specified in 52.21(a)(2)(iv)(b) and 52.21 (b)(3). Future projected actual emissions (PAE) and baseline actual emissions (BAE) are compared to determine whether a significant emissions increase would occur in accordance with 40 CFR 52.21(a)(2)(iv)(c). Contemporaneous emissions increases and/or decreases of actual emissions from other projects are also considered.

4.4 Emissions Analysis – Facility-Wide Changes

Facility-wide 2006/2007 baseline actual emissions versus projected emissions were also evaluated. For the 2006/2007 baseline, total boiler steam was produced from 94% coal and 6% gas. In addition, baseline emissions were also based on the operation of 3 coal-fired pulp dryers[4]. Future operations are based on: 1) 8,760 hours per year (365 days) operation at maximum capacities; 2) No. 1 and No. 2 B&W boilers and Union boiler firing natural gas only; 3) Riley boiler firing coal with low NO_x burners and natural gas[5] and; 4) Elimination of the 3 coal-fired pulp dryers.

Table 2 provides emission changes for all plant site emissions by comparing the facility emission sources from 2006/2007 to the future projected emissions. This comparison results in significant decreases in criteria pollutants. The emissions analysis shows a calculated annual increase in CO, VOC and CO_2 emissions, less than the respective significant emissions rates. The calculated increases are only due to conservative assumptions for future operations (for example, boilers operating at maximum capacities at 8760 h/y). Actual operations will be far less than 8760 hours per year. In reality emissions of all criteria pollutants will be less than historic levels as a result of the B&W boilers firing natural gas, shutdown of the coal-fired pulp dryers and the future installation of low NO_x burners on the Riley boiler.

Table 2. Summary of Facility-Wide Annual Baseline Actual Emissions (BAE 2006/2007) vs. Projected Actual Emissions (PAE)

Type of Emissions	PM[a] (t/y)	NO_x (t/y)	SO_2 (t/y)	CO (t/y)	VOC (t/y)	CO_2e (t/y)
Projected/Permitted	113	975	1617	2258	77	463,372
Baseline Actual	169	1963	2374	2241	73	418,807
Net Change	-56	-988	-757	+17	+4	+44,565
PSD SER[b]	15	40	40	100	40	75,000
Significant	No	No	No	No	No	No

[a] PM, PM_{10}, $PM_{2.5}$

[b] Significant Emission Rate

Daily Emissions Decreases

It is also worth highlighting that daily emissions are expected to decrease significantly when comparing future permitted operations versus baseline emissions. Estimated criteria pollutant decreases are as follows:

- No. 1 & No. 2 B&W Boilers — 85% reduction (all criteria)
- Riley Boiler Low NO_x Burners — 60.7% reduction in NO_x

Elimination of the coal-fired pulp dryers in 2006 also reduced total criteria pollutants by over 800 lbs per hour.

[4] Since the steam pulp dryer and shutdown of the coal pulp dryer occurred in December 2006, pulp dryer emissions were based on 2005/2006 beet campaign operations.

[5] As per the Tier II BART permit, on or after July 22, 2016 when firing coal, the Riley boiler is required to operate with low NO_x burners. Therefore, future emissions for the Riley boiler account for this permit requirement. In addition, for a PTE estimate, future Riley emissions are conservatively based on 86% coal firing and 14% natural gas.

4.5 Tier I Operating Permit Compliance Schedule – Permit to Construct Evaluation

As discussed during the pre-application meeting on October 8, 2015, this section of the application provides an update to a previous Permit to Construct (PTC) applicability evaluation for past equipment changes at the Nampa facility. The PTC evaluation is a requirement of Sections 14.12 and 14.13 of the Tier I Operating Permit. TASCO submitted the original PTC evaluation to IDEQ on June 3, 2004[6]. The discussion below includes key elements from the original application along with an updated applicability evaluation.

The potential applicability of the Permit to Construct requirements in IDAPA 58.01.01.200 through 58.01.01.208 were evaluated for two sets of projects as follows: 1) Projects specifically identified by IDEQ in the Nampa facility Tier I Permits, and 2) Other significant historical equipment construction and modification projects.

The focus of this updated review is previous equipment changes, which could impact emissions. As a result, the project review scope covered the time period beginning with the applicability date of the current Federal Prevention of Significant Deterioration (PSD) Rules (August 7, 1980) through the current date. Because the overriding factors affecting emissions are the beet harvest and seasonal operation of beet processing facilities, it was often difficult to determine whether specific equipment changes may have "resulted in" increased annual emissions. Most of the equipment or projects identified by IDEQ and TASCO as potentially subject to review involved minor or insignificant emission units installed or modified to facilitate greater utilization of existing plant capacity and overall process efficiency.

In this permit application, TASCO completed review of significant equipment changes, which may have impacted emissions to fulfill the Tier I Compliance Schedule. This includes: 1) The six historic projects identified in the Nampa facility Tier I Operating Permit as potentially subject to PTC requirements; 2) Significant emissions reductions due to the pulp steam dryer project and shutdown of three coal fired pulp dryers and; 3) Firing the B & W Boilers with natural gas only. Due to the difficulty in reconstructing past operating conditions, TASCO has not performed detailed emissions analyses for each individual project, and therefore has not concluded that any individual project constituted a major modification. To be conservative and to identify all possible air regulatory requirements that apply, TASCO assumed that all identified physical changes (those that were not obviously exempt from PTC requirements) could be grouped into a single project (hereinafter, the Project). This Project included physical/operational changes that occurred within the time period beginning with the first identified project commence construction date and thru September 2015.

4.5.1 Equipment Changes and Emissions Reduction Projects

Attachment B provides a listing and descriptions of principal changes and emissions reduction projects which have occurred at the facility since 1980. The listing is divided into 2 different time periods. The 1980 thru 2003 time period includes all projects which were in the 2004 permit application. The 2004 thru 2015 time period provides an updated list of equipment changes and emissions reductions projects.

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[6] Following the submittal of the original "Supplemental Tier I Permit Application" IDEQ determined the application incomplete in a letter dated July 2, 2004. Amalgamated and IDEQ representatives met on October 1, 2004 to discuss the incompleteness letter. Amalgamated provided additional information to IDEQ in a letter dated October 8, 2004 demonstrating that a Best Available Control Technology (BACT) analysis was not required. A follow up meeting was held in December 2005 to discuss the status of the application. Since then, Amalgamated and IDEQ efforts focused on completing a similar PTC evaluation for the Mini Cassia facility which was resolved in December 2013.

To the best of TASCO's knowledge all projects that may have significantly changed emissions are included in Attachment B.

It is important to highlight that during this period the primary emitting sources remained unchanged or were eliminated. These sources include the boilers and lime kilns which continue to operate and the previously operated coal-fired pulp dryers. Table 3 provides a summary of these sources.

Table 3. Primary Emissions Sources – Nampa Facility

Source	Year Installed	Fuel	Emission Controls
#1 & #2 B&W Boilers	1942	Coal & Natural Gas	Baghouse
Union Boiler	1957	Natural Gas	None
Riley Boiler	1968	Coal & Natural Gas	Baghouse
A Lime Kiln	1942	Coke	Baghouse (Bypass)
B Lime Kiln	1968	Coke	Baghouse (Bypass)
North Pulp Dryer[a]	1956	Coal & Natural Gas	Cyclones & Scrubbers
Center Pulp Dryer[a]	1968	Coal & Natural Gas	Cyclones & Scrubbers
South Pulp Dryer[a]	1968	Coal & Natural Gas	Cyclones & Scrubbers

[a]Permanently shutdown in December 2006

As shown, the boilers and lime kilns were installed prior to the promulgation of the New Source Review Rules. As a result of continuous facility energy efficiency improvements, process improvements have been accomplished without changes to the capacities of the boilers and lime kilns. One of the most significant improvements was the steam pulp dryer project, which eliminated three coal-fired pulp dryers in December 2006, significantly reducing emissions and the total amount of energy utilized by the facility.

4.5.2 Emissions Analysis – 1980 vs. Projected Emissions

For the purpose of fulfilling the Tier I Compliance Schedule requirement, TASCO has prepared a conservative emissions analysis of the equipment changes listed in Attachment B of this application. The emissions analysis was based on the following:

Baseline Emissions – There are a number of factors which make it difficult to establish a representative baseline emissions rate for a sugar beet processing facility. The number of days the Nampa facility operates is dependent on the size of the beet crop and other variables. During the 1970's, beet slicing days fluctuated from 81 days in 1974 to 137 days in 1972. Juice run days fluctuated from 89 days in 1977 to 127 days in 1972. Total facility operating days and equipment operations were well below the maximum operating capacities. Baseline emissions are also affected by the type of fuel fired by the boilers. Facility boilers can utilize either coal or natural gas or a combination of both fuels. Market fuel cost fluctuations determine whether coal or gas will be utilized.

The baseline emissions rate was conservatively based on the average of the 1979 and 1980 beet campaigns and juice runs. This baseline was selected because it coincides with the beginning of the Prevention of Significant Deterioration (PSD) rules and the diffuser replacement project (one of the six identified by IDEQ) which began operation during the 1981 beet campaign. Actual facility operating days, production rates and fuels were utilized to calculate emissions.

Projected Emissions – As previously discussed, future operations conservatively assume the facility and emission sources operate at the maximum potential to emit (maximum capacity at 8,760 hours per year).[7] Actual future operations will be much less than the PTE.

Combined Project Analysis – All projects since 1980 have been combined and analyzed as a single facility-wide modification. Combining the projects provides a worst-case analysis for assessing emissions changes. As previously discussed, the size of the beet crop has the largest influence on annual emissions.

Emissions Changes – Emissions changes were determined by subtracting the baseline emissions from the future emissions and comparing the result to the significant threshold levels found in IDAPA 58.01.01.006.92.

Using these assumptions ensures that the most conservative and appropriate regulatory analysis was conducted for the historic equipment evaluation. Table 4 provides a summary of the baseline emissions, future PTE and emissions changes associated with the historic review project. Detailed emission calculation spreadsheets with references are provided in Section 5 of this application.

Table 4. Summary of Facility Wide Baseline Actual Emissions (BAE 1979/1980) vs. Projected Emissions[c]

Type of Emissions	PM[a] (t/y)	NO_x (t/y)	SO_2 (t/y)	CO (t/y)	VOC (t/y)
Projected/Permitted	113	975	1617	2258	77
Baseline Actual	159	1607	1638	1912	50
Emissions Change	-46	-632	-21	+346	+24
PSD SER[b]	15	40	40	100	40
Significant	No	No	No	No	No

[a] PM, PM_{10}, $PM_{2.5}$

[b] Significant Emission Rate

c Initial assumption – Boilers operate at PTE or 8760[h]

As shown in Table 4 above, even with the conservative emissions assumptions PM, NO_x, SO_2 and VOC annual emissions changes are all below the significant emission rates. These analyses demonstrate that future projected annual PM, NO_x and SO_2 emissions are below 1979 and 1980 baseline emissions levels, over 35 years ago.

Calculated annual future emissions for VOC's and CO are above 1979 and 1980 levels. The higher emissions may be attributable to several factors including longer beet campaign operations and larger beet crops assumed for future operations. Future actual operations are expected to be well below the permitting assumptions. The 2258 tons CO per year projected/permitted emissions level provided in Table 4 is well below the annual CO limits provided in the Tier I Permit. The Tier I Permit combined total annual CO emission limit, for all sources at the facility, is 7227 tons per year.

[7] On December 31, 2002, Federal New Source Rule (NSR) Reform provisions were adopted in 67 Federal Register 80.186, which allows for actual-to-projected actual emissions to determine whether a modification is major. These reforms, along with other NSR/PSD requirements in 40 CFR 52.21, were incorporated by reference into the Rules for Control for Air Pollution in Idaho on February 5, 2004.

4.6 Other Applicable Requirements

This application has been prepared in accordance with the Permit to Construct (PTC) requirements in IDAPA 58.01.01.200. By firing natural gas only, emissions from the B&W boilers are expected to be well below Idaho's particulate (IDAPA 58.01.01.677) and opacity (IDAPA 58.01.01.625) standards. The facility will continue to operate in accordance with the existing Tier I Operating Permit and underlying Tier II Operating Permits.

In accordance with Idaho's Toxic Air Pollutant (TAP's) preconstruction standards (IDAPA 58.01.01.210), net emissions changes for this project were calculated. A listing of TAP's and emissions calculations is provided in Section 5.2.3 of this application. As shown, overall TAP's are expected to decrease by ~ 80% when firing natural gas exclusively and discontinuing coal combustion on these units.

4.7 Conclusions

This PTC application addresses several regulatory obligations. While the selection of natural gas for the B&W boilers exclusive fuel is not a modification triggering PTC review, the implications for TASCO's Boiler MACT Compliance, Tier II Permits, and the Tier I Compliance Schedule prompt submittal of this PTC application. The supporting documentation confirms that for most pollutants overall facility-wide emissions have decreased since the 1979 and 1980 baseline period used for the Tier I Permit PTC evaluation. These decreases are primarily attributable to: 1) The $20 million pulp steam dryer project completed in December 2006 which eliminated three coal-fired pulp dryers; 2) The continuous facility-wide energy conservation and reuse projects; 3) The boiler fuel selection; and 4) Other emissions reduction projects including the future installation of low NO_x burners on the Riley boiler.

TASCO requests that the Department consider the information provided in Section 4 sufficient to address: (1) PTC applicability for the B&W boiler fuel selection; (2) compliance with Boiler MACT; (3) conformity with existing Tier II permits, including BART; and (4) satisfaction of the Tier I Compliance schedule.

Attachment B

Condition 3.3 – Tier II BART Operating Permit (Issued 9/9/14)

&

September 17, 2014 IDEQ Letter – Morrie Lewis to Eric Erickson

AIR QUALITY

TIER II OPERATING PERMIT

Permittee	The Amalgamated Sugar Company LLC – Nampa Factory (TASCO-Nampa)
Permit Number	T2-2009.0105
Project ID	61426
Facility ID	027-00010
Facility Location	138 W. Karcher Ave. Nampa, ID 83653-8787

Permit Authority

This permit (a) is issued according to the "Rules for the Control of Air Pollution in Idaho" (Rules) (IDAPA 58.01.01.400–410); (b) pertains only to emissions of air contaminants regulated by the State of Idaho and to the sources specifically allowed to be constructed or modified by this permit; (c) has been granted on the basis of design information presented with the application; (d) does not affect the title of the premises upon which the equipment is to be located; (e) does not release the permittee from any liability for any loss due to damage to person or property caused by, resulting from, or arising out of the design, installation, maintenance, or operation of the proposed equipment; (f) does not release the permittee from compliance with other applicable federal, state, tribal, or local laws, regulations, or ordinances; and (g) in no manner implies or suggests that the Idaho Department of Environmental Quality (DEQ) or its officers, agents, or employees assume any liability, directly or indirectly, for any loss due to damage to person or property caused by, resulting from, or arising out of design, installation, maintenance, or operation of the proposed equipment. Changes in design, equipment, or operations may be considered a modification subject to DEQ review in accordance with IDAPA 58.01.01.200–228.

Date Issued September 19, 2014

Date Expires December 23, 2016

Morris Lewis

Morrie Lewis, Permit Writer

Mike Simon

Mike Simon, Stationary Source Manager

3. BOILERS

3.1 Process Description

The Nampa factory operates three industrial boilers each fired by pulverized coal and/or natural gas to supply steam and generate electricity for processing of sugar beets into sugar and byproducts, including animal feed at the Nampa facility. These boilers are the one Riley Boiler and two Babcock & Wilcox (B&W) Boilers.

3.2 BART and BART Alternative Control Equipment Descriptions

- BART for the control of PM emissions is the existing Baghouse (A-B3) on the Riley Boiler.
- BART for the control of NO_x emissions is Coal-Firing LNBs on the Riley Boiler.
- The BART Alternative to the control of SO_2 emissions is Coal-Firing LNBs on B&W Boiler #1 and Coal-Firing LNBs on B&W Boiler #2 for the control of NO_x, and shutdown of the three coal-fired Pulp Dryers (S-D1, S-D2, and S-D3) for the control of PM, NO_x, and SO_2.

Compliance Dates

3.3 BART 40 CFR 51.308, Subpart P – BART Control Equipment Installation and Operation Due Date

In accordance with IDAPA 58.01.01.668.04 and 40 CFR 51.308(e)(1)(iv), the permittee shall comply with the following as expeditiously as practicable, but in no event later than July 22, 2016:

- Install and operate BART controls on the Riley Boiler (Permit Conditions 3.6 and 3.7), unless the Riley Boiler is fired using natural gas only;
- Install and operate BART Alternative controls on B&W Boiler #1 (Permit Condition 3.7), unless B&W Boiler #1 is fired using natural gas only;
- Install and operate BART Alternative controls on B&W Boiler #2 (Permit Condition 3.7), unless B&W Boiler #2 is fired using natural gas only.

The permittee may submit a request to obtain DEQ-approved BART alternatives and to revise this permit in accordance with IDAPA 58.01.01.404.04. DEQ will process the request in accordance with IDAPA 58.01.01.404. The request must be submitted timely such that any revisions to this permit and the corresponding revision to the Regional Haze State Implementation Plan (RH SIP) are approved prior to July 22, 2016. Pursuant to Section 110(k)(2) of the Clean Air Act, EPA has 12 months to act on a requested SIP revision.

Emissions Limits

3.4 BART 40 CFR 51.308, Subpart P – BART Emission Limits

On and after July 22, 2016, emissions from the Riley Boiler shall not exceed any corresponding emission rate limit listed in the following BART Emission Limits Table, in accordance with 40 CFR 51.308(e) and IDAPA 58.01.01.668.

BART EMISSION LIMITS TABLE [a]

Source Description	PM_{10} lb/hr [b][c]	NO_x lb/hr [b][c]
Riley Boiler	12.4	147

a) In absence of any other credible evidence, compliance is assured by complying with permit operating, monitoring, and recordkeeping requirements.

b) Pounds per hour as determined by the prescribed test method (Permit Condition 2.4), or alternative test method approved by DEQ in accordance with IDAPA 58.01.01.157.

c) BART emission rate limit established pursuant to 40 CFR 51.308(e).

STATE OF IDAHO
DEPARTMENT OF
ENVIRONMENTAL QUALITY

1410 NORTH HILTON, BOISE, ID 83706 · (208) 373-0502

C. L. "BUTCH" OTTER, GOVERNOR
CURT FRANSEN, DIRECTOR

September 17, 2014

VIA E-MAIL

Eric Erickson, PE, CEM
Plant Manager
The Amalgamated Sugar Company LLC (TASCO-Nampa)
P.O. Box 8787
Nampa, Idaho 83687

RE: Emissions reduction strategy concurrence and typographical correction
Facility ID No. 027-00010, TASCO-Nampa

Dear Mr. Erickson:

On August 19, 2014, the Department of Environmental Quality (DEQ) received a permitting exemption concurrence request from TASCO-Nampa. Based on a review of the concurrence request and emission estimates, applicable state and federal rules and regulations, and the permit, DEQ has determined that the proposed boiler emissions reduction strategy is permitted by Tier II Operating Permit No. T2-2009.0105 PROJ 60867. Implementing the proposed strategy would not meet the definition of modification as defined in IDAPA 58.01.01.006 (*Rules for the Control of Air Pollution in Idaho*).

Proposed emissions reduction strategy

In lieu of installation of coal-firing LNB in the B&W boilers, permanent conversion of the B&W boilers to full-time natural gas firing (only) has been proposed – in addition to the retrofit of coal-firing low NO_x burners (LNB) on the Riley Boiler – to achieve compliance with both BART and Boiler MACT emission limitations.

BART Pollutant	Surplus-to-BART Alternative Emission Reductions [a] (tons per year)
PM	51.4
SO_2	434.8
NO_x	23.6

(a) Surplus PM, SO_2, and NO_x emission reductions for the proposed emission reduction strategy of firing natural gas only in the B&W boilers, when compared to emission estimates from the BART Alternative scenario in Table 6 of the Statement of Basis to T2-2009.0105 PROJ 60867 (2011AAG1834[v5]).

DEQ recognizes that additional emission reductions achieved in the proposed strategy would be surplus to reductions required to achieve compliance with BART Alternative emission limits, and would further regional progress goals in Idaho's Regional Haze program.

Clarification and discussion of permit conditions pertaining to the B&W boilers

- Although not explicitly stated in the coal-firing LNB requirements (Permit Condition 3.7), if B&W Boilers #1 and #2 are both fired using only natural gas, DEQ agrees that installation and operation of coal-firing LNB on these boilers would not be applicable. This is supported by the operative phrasing "*...at all times the B&W Boiler...is fired by coal...*" in Permit Condition 3.7, which is specifically referenced by Permit Condition 3.3. For clarification purposes, potentially confusing and contradicting language will be corrected as described below (Permit Condition 3.3).
- As provided in the compliance notification requirements (Permit Condition 3.16) and the construction and operation general provision (General Provision 5), notification of initiation of construction, anticipated start-up, and actual start-up of coal-fired LNB is required. If coal-fired LNB are not installed on both of the B&W boilers, DEQ also requests that TASCO-Nampa provide written notification within 15 days after completing conversion of B&W Boilers #1 and/or #2 to natural gas. This supplemental notification should include a description of the method used to ensure permanent removal of coal firing from each boiler, as applicable. To ensure ongoing compliance after the BART compliance deadline, DEQ may revise permit conditions pertaining to the B&W boilers to remove non-applicable requirements and to establish federally-enforceable requirements for the combustion of natural gas only (as a permit revision or renewal).
- As described in the performance testing requirements (Permit Conditions 3.11 – 3.13), upon startup of the Riley Boiler coal-firing LNB (Permit Condition 3.11), performance testing of the Riley Boiler, B&W Boilers #1 and #2 are required within 180 days to demonstrate compliance with all boiler emission limits and to determine all boiler CO emission rates.

Proposed typographical correction

Although the intent to allow for natural gas firing in the B&W boilers is clear in the coal-firing LNB requirements (Permit Condition 3.7), when paired with the BART and BART Alternative compliance due date requirement (Permit Condition 3.3) there is an apparent inconsistency, which could incorrectly lead to the conclusion that installation of coal-firing LNB would still be required even when coal will not be fired. For clarification purposes, a revision to Tier II Operating Permit No. T2-2009.0105 PROJ 60867 is forthcoming in which this condition will be revised as follows:

3.3 ***BART 40 CFR 51.308, Subpart P – BART Control Equipment Installation and Operation Due Date***

In accordance with IDAPA 58.01.01.668.04 and 40 CFR 51.308(e)(1)(iv), the permittee shall comply with the following as expeditiously as practicable, but in no event later than July 22, 2016:

- *Install and operate BART controls on the Riley Boiler (Permit Conditions 3.6 and 3.7), unless the Riley Boiler is fired using natural gas only;*
- *Install and operate BART Alternative controls on B&W Boiler #1 (Permit Condition 3.7), unless B&W Boiler #1 is fired using natural gas only;*
- *Install and operate BART Alternative controls on B&W Boiler #2 (Permit Condition 3.7), unless B&W Boiler #2 is fired using natural gas only.*

The permittee may submit a request to obtain DEQ-approved BART alternatives and to revise this permit in accordance with IDAPA 58.01.01.404.04. DEQ will process the request in accordance with IDAPA 58.01.01.404. The request must be submitted timely such that any revisions to this permit and the corresponding revision to the RH SIP are approved prior to July 22, 2016. Pursuant to Section 110(k)(2) of the Clean Air Act, EPA has 12 months to act on a requested SIP revision.

This letter is in no way intended to supersede any other federal, state, or local rules and regulations that may apply. Also, be advised that this letter does not constitute a waiver of any compliance actions that may result from misinformation or noncompliance of the criteria set in the submittal received for this project that may cause unreasonable risk to human or animal life, or violate any ambient air quality standard.

If you have any questions regarding this letter or about the air quality permitting process, please contact me at (208) 373-0502 or Morrie.Lewis@deq.idaho.gov.

Sincerely,

Morrie Lewis
Permit Writer
Air Quality Division

Project No. 61417

ATTACHMENT C

Principal Process Equipment Changes & Emissions Reduction Projects

1980 – 2003

The following list of principal process equipment changes and emissions reduction projects from 1980 thru 2003 were previously submitted to IDEQ in the 2004 Supplemental Tier I Operating Permit application. As discussed in Section 3 of the 2004 application, two sets of projects were evaluated: 1) Projects specifically identified by IDEQ in the Nampa facility Tier I permit, and 2) Other construction or equipment changes which could impact emissions.

Diffuser Replacement (1980 – IDEQ #2). In 1980, the chain diffuser was replaced with a more efficient tower diffuser. The replacement was needed because of the deteriorated condition of the chain diffuser that was originally installed in 1947. The tower diffuser had the same rated capacity as the chain diffuser it replaced. The diffuser itself does not emit pollutants. Because the tower diffuser is more efficient than the diffuser it replaced, (i.e., less water was required to extract soluble sugar), it substantially reduced the use of steam per ton of beets processed. This in turn substantially reduced the boiler emissions per ton of beets processed.

Improved energy efficiency along with fine tuning of the operation may have led to increased beet processing. Annual emissions are a function of crop size and equipment utilization. Depending on the size of the beet crop, these improvements may have increased emissions.

#2 Cooling Granulator (1981 – IDEQ #4). During 1981 an additional cooling granulator (with dust box for controlling sugar dust) was constructed to share the total sugar production from the drying granulator with the existing cooling granulator. The existing cooling granulator did not sufficiently cool the production sugar. The installation of the additional cooling granulator resulted in reduced throughput through each cooling granulator and improved sugar quality. Airflow through the existing and new dust boxes was significantly reduced resulting in reduced overall particulate emissions from the system. In 1996, the dust boxes were replaced with a baghouse, further reducing particulate emissions.

Installation of Sugar Juice Storage Tanks #7, #8 and #9 (1982, 1988, 1989, Large Crop Years – IDEQ #1). To accommodate large beet crops, three additional juice tanks were installed over an eight-year period to coincide with three large crop years. The tanks were needed to reduce the logistical issues and high cost of storing thick juice in railroad cars during the large crop years. The tanks themselves do not emit pollutants. For large beet crops, annual emissions may have increased from the sugar end and boilers due to increased operating days during the juice run. To the extent additional juice storage allowed the factory to operate at full slice capacity, no emission increase is likely due to the avoidance of processing badly deteriorated beets. Avoiding the processing of badly deteriorated beets may have reduced emissions.

Changes in Pulp Presses (1985, 1989, 1990). Three large presses were installed in 1985, 1989, and 1990. The large press in 1990 replaced the smaller press. With the addition of the new presses the pulp pressing system could produce more pressed pulp with a lower moisture content.

The capacity of the dryers, which is based on the tons of water evaporated, remained unchanged. There were no significant physical changes to the dryers, and, in particular, no change has been made to the dryers that would allow more fuel or more pulp to be added. Pulp presses are not emissions sources.

Lower moisture pulp requires the use of less fuel in the pulp dryers, resulting in lower emissions per ton of pulp dried.

Drying Granulator Replacement (1987 – IDEQ #3). The existing drying granulator was replaced with a larger unit to properly dry sugar to the moisture content necessary to maintain acceptable sugar quality. The existing 6' by 26' drum was replaced with an 8.5' by 36' drum. The increased capacity from the sugar drying system increased sugar throughput both on a short-term and long-term basis. This project in conjunction with other projects increased the capacity of the sugar end equipment. A "dust box" which is a scrubber which utilizes sugar juice, controls sugar dust from this system. Based on an engineering stack test, sugar dust emissions are insignificant from this source.

Addition of Low Raw Pan (1991). An additional low raw pan was installed in 1991 to improve sugar end production efficiencies by increasing retention time of the low raw system. Increased retention time leads to larger crystals, which separate more easily from syrups (less wash water use). The low raw pan does not emit pollutants. This pan is only a small component of the sugar end equipment and did not impact overall factory emissions.

"A" Side 2nd Carbonation Replacement (1991). The "A" Side 2nd Carbonation tank and gas distributors were replaced because of the deteriorated state of the existing system. The existing system was replaced with a modern system with improved gassing height and CO_2 distribution. The new system provides higher 2nd carbonation efficiency and higher thin juice purity.

Molasses Desugarization Chromatographic Separator (1994 – IDEQ #5). The Chromatographic Separator (CS) for desugarizing molasses was installed in 1994 and began operation in 1995. TASCO developed this technology to replace the Quentin ion exchange process with a more environmentally friendly process. The CS process consisted of pretreatment, separator cells, resin system, evaporators and tanks.

The CS is a simulated moving liquid chromatography process. Feed materials for the process are molasses (from the Nampa facility or other facilities) and water. Products include extract (high purity sugar juice), raffinate (low purity sugar juice), and other organic materials, such as liquid betaine. Evaporators are used to concentrate the products. Concentrated extract is either stored or piped to the sugar end to be processed into sugar. Raffinate is concentrated into concentrated separator byproduct (CSB) and sold. CSB can be added to pulp before drying, used as a dust suppressant, or sold directly as an animal feed supplement.

Compared to the Quentin process the CS improved sugar recovery and required no increased steam consumption from existing boilers. Steam load for evaporation in the CS project was equal to the steam evaporation in the replaced Quentin process. Annual emissions from the facility increased due to longer operation of the separator equipment and sugar end operation.

A significant environmental benefit of this project was the discontinuation of the Quentin process. The Quentin process discharged brine waste to onsite ponds. Elimination of these ponds reduced groundwater impacts and odors from the ponds. A self-exemption analysis for this project was submitted and accepted by the Department.

White Pan Addition (1994). An additional white pan (for a total of three) was installed during the same time period as the CS project. The installation of the pan resulted in increased sugar production capacity and decreased juice flow to tank storage during the beet campaign. The white pan in itself does not emit pollutants. At about the same time, the factory was required to boil coarser sugar which consumed most of the additional sugar production capacity. Increased steam utilization may have occurred within the maximum permitted operating capacity of the existing boilers.

Betaine Concentration Project, Phase 1 (1996). The betaine concentration project reconfigured the thin juice evaporator train to concentrate betaine during the intercampaign. Betaine was already being evaporated with the CSB in the CS project noted above. The ability to recover betaine resulted from installation of the CS. The thin juice evaporators themselves do not emit pollutants and overall factory emissions likely remained the same.

Reserve and Parallel Power (1998 – IDEQ #6). The electrical service for the facility was paralleled with Idaho Power in 1998 to provide a more stable supply of energy. Commercial sales did not occur until 2000 when it was determined that electricity sales could be accomplished with little impact to the facility. The production (in kilowatt hours) by year is presented below.

Year	Electric Generation (kilowatt hours)
1998	0
1999	0
2000	6111
2001	1,859,414

The additional emissions caused by selling the power above are below regulatory concern.

Energy Savings System (1998). The energy saving system was installed to improve the energy efficiency of the facility. The steam savings were realized by replacing a plate and frame heat exchanger, relocating a plate and frame HTR 204 to heat soft water during juice run, modifying the Union boiler piping to be able to base load the Riley boiler, and installing turbine/generator protection relays and communication package with Idaho Power. The energy saving project likely resulted in a reduction of steam demand and associated boiler emissions.

New 1A Falling Film Evaporator (2000). A new 1A falling film evaporator was installed in 2000 to reduce steam consumption and provide materials of construction that were compatible with softened thin juice (from the new thin juice softener). The installed heat transfer surface area was increased by 31% as a result of the project. The improved surface area provided improved steam economy for the factory and decreased the associated emissions from the boiler system. This project did not increase the capacity of the evaporation system since the rate limiting process of the beet end is a combination of the diffuser and availability of boiler steam.

DDS Juice Purification, Phase I and II (2000). In 2000 the existing juice purification system was replaced with a more efficient, state-of-the-art, DDS juice purification system. The DDS system includes a prelimer, cold limer, hot main limer, and first carbonation vessel. Following the installation of the DDS system, the amount of lime and coke per ton of beets processed decreased. This also improves white sugar recovery by improving the purity profile for the sugar end operation. This project did not increase the capacity of the juice purification system since the rate limiting process of the beet end is a combination of the diffuser and availability of boiler steam. A self-exemption analysis for this project was submitted to IDEQ.

Compared to the previous BMA/Benning juice purification system, the DDS system has required less lime and CO_2 gas to purify the sugar juices. This reduction may be attributed to improved mixing of lime and raw sugar juices and improved CO_2 gas distribution within the carbonation tank vessels.

Due to the improved efficiency, actual emissions likely decreased from the juice purification system and lime kilns. VOC's are primarily generated from thin juice in the carbonation tanks. Bubbles of CO_2 from the lime kilns are introduced at the bottom of the carbonation tanks. The gas bubbles agitate the sugar juice releasing organic vapors.[1] The carbonation system associated with the DDS system included Richter tubes and a taller gassing height, which improved the distribution of CO_2 gas. With less CO_2 gas, VOC's emissions from the carbonation system likely decreased.

This project also slightly reduced emissions from the lime kilns and boilers. Improved lime utilization reduces lime rock and coke consumption in the kilns and an associated reduction in emissions. Boiler emissions probably decreased slightly, due to less dilution water added for lime coke desweetening and sugar washing.

Emissions Reductions Projects

Since 1992, the following is a listing of additional air pollution control equipment which reduced emissions at the facility. Several of these projects were developed in coordination with IDEQ.

1983 Pulp Dryer Dust Collector. The pulp dryer dust collection system began operation in 1966 to reduce building emissions and collect product associated with pulp bagging and weight-o-meter operation. The pulp dryer dust collection was updated in 1983 and again in 1995 to recover more fugitive pulp material and to improve working conditions inside the building.

1984 Addition to Riley Baghouse. The original baghouse for the Riley boiler was under-designed. This addition helped to minimize the practice of bypassing the baghouse during upsets. The addition of one cell in the baghouse increased bag area by 17% and decreased the pressure drop across the baghouse. This addition likely reduced particulate emissions from the Riley boiler.

1987 Replace South Dryer Scrubbers. The South pulp dryer scrubber vessels had deteriorated to the point that they were no longer repairable. The scrubbers were replaced in 1984 with 316 SS vessels that assured longer service life. The spray system design was modified to reduce scaling of the impingement area. Emissions reduction likely resulted from this replacement.

1992 Lime Kiln Scrubbers. Visible emissions from the lime kiln bypass vent were determined to be out of compliance by DEQ during the crop year 1991 beet campaign. The kiln vents were routed through a new wet scrubber to ensure compliance.

1994 Lime Kiln Bag House. The wet scrubber for the lime kiln vents was replaced with a new baghouse to ensure the lime kiln bypass vent is in compliance with the Visible Emissions (VE) Standards.

1993, 1994 North Pulp Dryer Scrubber Replacement. During 1992 source testing, compliance with air emission standards could not be demonstrated. To ensure compliance, the design of the North Dryer scrubber was modified to the same design that was used when the South Pulp dryer scrubber was modified.

1993 Sugar Warehouse Dust Collection Upgrade. The project consisted of expanding the ductwork of the existing dust collectors to address cleanup issues in the packaging room. The project was justified based on reduced employee exposure to sugar dust, reduced explosion potential of fugitive sugar dust within the building and improved product recovery.

[1] Sugar juice VOC's are likely very similar to vapors people smell when cooking vegetables in a kitchen. Therefore, VOC's from this source are not hazardous.

1996 Cooling Granulator Baghouse. The dust boxes on the cooling granulators were replaced with baghouses. This project further reduced sugar dust from the granulators. In addition, steam required to heat the dust box solution tank was eliminated. Therefore, steam demands were slightly reduced.

2003 Pellet Cooler Baghouse. Cyclones for controlling particulates from the pellet coolers were replaced with a baghouse as per the Tier II Operating Permit. This further reduces particulates from the pellet coolers.

Principal Process Equipment Changes & Emissions Reduction Projects

2004 Thru 2015

Utilizing the same criteria as provided in the 2004 permit application, attached are additional equipment changes and emissions reduction projects from 2004 thru 2015. As discussed below, several of the equipment changes were either approved by IDEQ or exempted from obtaining a PTC since emissions remained unchanged or were expected to decrease.

Sugar Juice Tank #10 (2004). Due to an extraordinary large crop for the 2003-2004 beet campaign, juice production exceeded the capacity of the existing tank farm. In order to accommodate the extra juice, an additional thick juice tank was needed. Following discussions with IDEQ, a PTC application was prepared and a PTC was issued on January 12, 2004. The purpose of the PTC was for thick juice storage in Tank #10, from beets processed at the Nampa facility during the 2003 crop year. Filling of Tank #10 was completed on February 7, 2004. As per Section 2.4 of the permit, Tank 10 shall not be used to store and transfer thick juice from the Nampa facility. This condition was further clarified in 2006 and IDEQ concurred that transfer and storage of thick juice from offsite sources (Mini Cassia and Twin Falls facilities) is not limited.

Betaine Crystallization (2004, 2006). This project allowed for the production of crystalline betaine. Equipment consisted of evaporators, betaine separator system, crystallization and separation equipment, product dryer/cooler and packaging equipment. The Nampa facility provided a PTC exemption analysis to IDEQ on 1/7/2004. IDEQ concurred that a PTC was not required on 2/20/2004. In 2006, a new betaine high raw pan and centrifugal were added to improve product recovery.

Steam Pulp Dryer & Supporting Equipment (2007). In 2007 the Nampa facility completed construction and began full operation of a steam pulp dryer. The steam dryer significantly reduced emissions by eliminating three direct coal-fired rotary drum dryers. This state-of-the-art dryer was a significant environmental improvement for the Nampa facility and is part of IDEQ's Northern Ada County PM-10 Maintenance Plan.

TASCO worked cooperatively with IDEQ by committing to this $20 million steam dryer project. A project schedule was incorporated into the 2002 Tier II Operating Permit and subsequently the Tier I Operating Permit. Although the Tier II permit allowed for partial operation of one direct fired, rotary pulp dryer drum, Amalgamated made the decision to completely shut down all three pulp dryer drums, demonstrating Amalgamated's ongoing commitment to further protect air quality in the Treasure Valley. The Nampa facility submitted a new source review exemption analysis to IDEQ on November 29, 2002. On March 10th, 2003 Amalgamated received IDEQ's concurrence stating that a PTC was not required for this emissions reduction project.

Elimination of the three coal-fired dryers significantly reduced overall facility wide emissions and by reducing coal usage amounts by 200 tons per day during the beet processing campaign. Most importantly, daily emissions were reduced during the fall and winter months. As per IDEQ's PM-10 Maintenance Plan, winter months were identified as a high priority period for emissions reductions. Total annual criteria pollutant emissions were estimated to be reduced by ~1000 tons per year.

Steam for the dryer is provided by existing boilers. A prerequisite for the steam dryer was the installation of a transformer evaporator which occurred in 2004. As discussed in the 2002 NSR exemption analysis, this evaporator was needed to recover steam from the pulp steam dryer.

Coupled Loop Molasses Separator Configuration (2008). In order to improve the performance of the molasses separator, the separator was converted to a coupled loop operating mode. The project required two supply tanks and piping changes. The primary purpose of this project is to improve recovery of betaine. Based on a steam balance assessment for this configuration, energy usage was expected to remain the same or decrease.

Process Improvement Projects (2010-2012). Separator and sugar end efficiency improvements were completed over a two year period beginning in 2010. The project consisted of reconfiguring existing and installation of new equipment including new separator equipment, installation of a continuous raw pan, modernization of centrifugal stations, installation of a new vertical crystallizer and upgraded controls of existing white pans. These projects were designed so that steam consumption rates and air emissions would not increase during all modes of operation. As a result, these improvements were exempt frrom PTC requirements. A PTC exemption evaluation was previously submitted and discussed with IDEQ in December 2009.

#7 White Centrifugal (2012). A seventh white sugar centrifugal was installed as a spare to replace the production of the other six centrifugals as they are individually removed from service for repairs or maintenance. This sustains nominal six centrifugal production on a continuous basis.

Sugar Packaging Lines (2005, 2008, 2012). Automated packaging (2005), powdered sugar packaging (2008), retail packaging (2012).

Byproducts Tanks (2013, 2014, 2015). Tanks were installed for storage of concentrated separator byproduct (CSB) which is principally sold as an animal feed byproduct. The primary purpose of these tanks were to provide long-term storage of the animal feed byproduct to for sales throughout the year. In 2015, two tanks were replaced with one tank to maximize sales.

Heat Exchangers (Calandrias) – Maintenance & Repair (2003, 2004, 2006, 2008, 2014, 2015). To ensure energy efficient facility operations, evaporator heat exchangers (calandrias) have been routinely replaced or upgraded. These projects include: 1) Replace calandria in Evaporator 4A-2 (2003); 2) Replace calandria in Evaporator 4B (2004); 3) Replace calandria in Evaporator 5A (2006); 4) Evaporator 5B upgrade; 5) Replace calandria in #3 White Pan (2014) and 6) Replace calandria in #2 White Pan (2015). Heat exchanger replacements or upgrades allow for more efficient use of boiler steam.

Heater Replacements (2012, 2013, 2015). To ensure energy efficient facility operations, heaters or heat exchangers have been replaced. These projects include: 1) Replacement of A-side Press Water Heater (2012); Replacement of A-side Circulation Juice Heater (2013) and; 3) Replacement of B-side Circulation Juice Heater (2015).

Boiler House Control Upgrades (2010, 2013, 2014, 2015). This project consisted of five phases to replace and modernize the boiler control systems. Previous combustion and burner management systems were replaced with new equipment. Improved controls are expected to improve combustion and energy efficiencies.

Natural Gas Only – No. 1 & No. 2 B&W Boilers (2015/2016). As per this PTC application, the Nampa facility is committing to firing natural gas only in the No. 1 and No. 2 B&W boilers. The ability to fire pulverized coal in these boilers will be eliminated. This commitment further reduces both daily and annual emissions from the Nampa facility.

Section 5
Emissions Estimates and Limitations

This section provides a detailed evaluation of the emissions changes associated with the B&W boilers firing natural gas only and to address the Tier I Permit Compliance Schedule projects. Overall, this commitment will result in significant reductions in criteria pollutants, Greenhouse Gases (GHG's) and hazardous air pollutants (HAP's). Emissions changes are provided for the No. 1 and No. 2 B&W boilers only and also on a facility-wide basis. This section is divided into the following subsections:

- Section 5.1 Facility Classification. The facility classification is based on the 2014 AERR submittal to IDEQ.

- Section 5.2 No. 1 and No. 2 B&W Boiler Emissions. Baseline emissions were calculated based on 2006/2007 average operations while primarily firing coal. Future projected emissions are conservatively based on the No. 1 and No. 2 boilers firing natural gas and operating 8,760 hours per year. Criteria pollutants, greenhouse gases (GHG's) and HAP's/TAP's emissions estimates are provided.

- Section 5.3 Facility Emissions Reductions Projects. Short and long-term (lbs/h and tons/y) emissions reduction calculations are provided for this project and for the: 1) Three coal-fired pulp dryers which were permanently shut down in December 2006; and 2) NO_x reductions for the future installation of coal-firing low NO_x burners (LNB) on the Riley boiler.

- Section 5.4 Comparison of Facility Projected vs. Baseline Emissions. As discussed in the Applicable Requirements (Section 4), two different scenarios are provided. The first scenario compares future projected/permitted criteria pollutant emissions with 2006/2007 emissions estimates. The second scenario compares future projected/permitted criteria pollutant emissions with 1979/1980 emissions estimates.

- Section 5.5 Facility GHG's – Projected vs. Baseline. GHG's are estimated based on the same scenarios as provided in Section 5.4.

- Section 5.6 Facility HAP's. Facility projected HAP's are provided in this section.

Section 5.1
Facility Classification
The Amalgamated Sugar Company LLC
Nampa Facility

Sugar beet processing facilities are not on the list of designated facilities as per IDAPA 58.01.01.006.30. Actual and potential emissions from the Nampa facility are greater than 100 tons per year. Therefore, in accordance with IDAPA 58.01.01.006.55, the facility is a major source.

The facility is located in Canyon County, which is part of Air Quality Control Region 64. This area is in attainment or unclassifiable for all criteria pollutants. Canyon County has also been designated by IDEQ as part of the "Treasure Valley Air Shed Management Plan Area".

Section 5.2.1
No. 1 & No. 2 B&W Boilers – Criteria Pollutants

B&W Boiler Natural Gas Conversion Project
2006-2007 Baseline Emissions vs Future Projected Emissions
The Amalgamated Sugar Co. LLC
Nampa Facility

Stack & ID	PM[a] (lbs/h)	PM[a] (tons/y)	NOx (lbs/h)	NOx (tons/y)	SO2 (lbs/h)	SO2 (tons/y)	CO (lbs/h)	CO (tons/y)	VOC (lbs/h)	VOC (tons/y)
No. 1 B&W Boiler - Baseline	6.5	9.1	155	209	189	339	18.6	27.8	1.13	0.82
No. 2 B&W Boiler - Baseline	6.5	10.3	155	236	189	383	18.6	31.5	1.13	0.93
No. 1 & 2 B&W Boilers -Future	2.9	12.5	79.4	348	0.15	0.66	6.3	27.6	1.39	6.07
Net Change	-10.1	-6.9	-231	-97.6	-378	-721	-30.9	-31.7	-0.9	4.3

[a] PM, PM10 and PM2.5

B&W Boiler Natural Gas Conversion Project
2006-2007 Baseline Emissions(Coal)
The Amalgamated Sugar Co. LLC
Nampa Facility

Source Name	Source ID	Production (klbs steam) Max Hourly	Daily	Annual	Parameter	Factor	Emissions Units	Reference	Emissions (lbs/h)	(tons/y)
No. 1 B&W Boiler Pulverized Coal	S-B1	105	95.6	376,882	PM & PM10	0.048	lbs/klb steam	Bolier MACT Limit (0.04 lb/MMBtu limit)	5.0	9.0
		105	95.6	376,882	NOx	1.1	lbs/klb steam	Eng Stack Test 2009	115.5	207.3
		105	95.6	376,882	SO2	1.8	lbs/klb steam	AP-42,9/98, Table 1.4-1	189.0	339.2
		105	95.6	376,882	CO	0.147	lbs/klb steam	Eng. Stack Test 2009	15.4	27.7
		105	95.6	376,882	VOC	0.0042	lbs/klb steam	AP-42,9/98, Table 1.4-1	0.44	0.79
Natural Gas	S-B1	105	NA	8,817	PM & PM10	0.0136	lbs/klb steam	Nov. 2004 Compliance Test and 100% safety factor	1.43	0.06
		105	NA	8,817	NOx	0.378	lbs/klb steam	AP-42,9/98, Table1.4-1	39.7	1.7
		105	NA	8,817	SO2	0.00072	lbs/klb steam	AP-42,9/98, Table1.4-2	0.1	0.0
		105	NA	8,817	CO	0.03	lbs/klb steam	AP-42,9/98, Table1.4-1	3.2	0.1
		105	NA	8,817	VOC	0.0066	lbs/klb steam	AP-42,9/98, Table1.4-2	0.69	0.03

Total		PM & PM10	6.5	9.1
		NOx	155.2	209.0
		SO2	189.1	339.2
		CO	18.6	27.8
		VOC	1.1	0.8

Source Name	Source ID	Production (klbs steam) Max Hourly	Daily	Annual	Parameter	Factor	Emissions Units	Reference	Emissions (lbs/h)	(tons/y)
No. 2 B&W Boiler Pulverized Coal	S-B2	105	95.6	425,405	PM & PM10	0.048	lbs/klb steam	Bolier MACT Limit (0.04 lb/MMBtu limit)	5.0	10.2
		105	95.6	425,405	NOx	1.1	lbs/klb steam	Eng Stack Test 2009	115.5	234.0
		105	95.6	425,405	SO2	1.8	lbs/klb steam	AP-42,9/98, Table 1.4-1	189.0	382.9
		105	95.6	425,405	CO	0.147	lbs/klb steam	Eng. Stack Test 2009	15.4	31.3
		105	95.6	425,405	VOC	0.0042	lbs/klb steam	AP-42,9/98, Table1.4-1	0.44	0.89
Natural Gas	S-B2	105	NA	12,320	PM & PM10	0.0136	lbs/klb steam	Nov. 2004 Compliance Test and 100% safety factor	1.43	0.08
		105	NA	12,320	NOx	0.378	lbs/klb steam	AP-42,9/98, Table1.4-1	39.7	2.3
		105	NA	12,320	SO2	0.00072	lbs/klb steam	AP-42,9/98, Table1.4-2	0.1	0.0
		105	NA	12,320	CO	0.03	lbs/klb steam	AP-42,9/98, Table1.4-1	3.2	0.2
		105	NA	12,320	VOC	0.0066	lbs/klb steam	AP-42,9/98, Table1.4-2	0.69	0.04

Total		PM & PM10	6.5	10.3
		NOx	155.2	236.3
		SO2	189.1	382.9
		CO	18.6	31.5
		VOC	1.1	0.9

Future Projected Emissions (Natural Gas)

Source Name	Source ID	Production Max Hourly	Daily	Annual	Parameter	Factor	Emissions Units	Reference	Emissions (lbs/h)	(tons/y)
No1 & 2 B&W Boiler Natural Gas	S-B1 & S-B2	210	5040	1,839,600	PM & PM10	0.0136	lbs/klb steam	Nov. 2004 Compliance Test and 100% safety factor	2.9	12.5
		210	5040	1,839,600	NOx	0.378	lbs/klb steam	AP-42(9/98), Table 1.4-1	79.4	347.7
		210	5040	1,839,600	SO2	0.00072	lbs/klb steam	AP-42(9/98), Table 1.4-2	0.15	0.66
		210	5040	1,839,600	CO	0.03	lbs/klb steam	AP-42,9/98, Table1.4-1	6.3	27.6
		210	5040	1,839,600	VOC	0.0066	lbs/klb steam	AP-42,9/98, Table1.4-2	1.39	6.07

mes 365 day per year operation

Section 5.2.2
No. 1 & No. 2 B& W Boilers – Greenhouse Gases

B&W Boiler Natural Gas Conversion Project
2006-2007 Baseline Emissions vs Future Projected Emissions
GHG Net Emissions Summary
Nampa Facility

Source	CO_2 (tons/y)	CH_4 (tons/y)	N_2O (tons/y)	CO_2e (tons/y)
No. 1 B&W Boiler - Baseline	50953	5.7	0.8	51342
No. 2 B&W Boiler - Baseline	57685	6.4	0.9	58124
No. 1 & No. 2 B&W Boilers - Future	133371	3	0.3	133512
Net Change	24733	-9	-2	24046

B&W Boiler Natural Gas Conversion Project
GHG Emissions Estimates
2006-2007 Baseline Emissions (Coal)
The Amalgamated Sugar Co. LLC
Nampa Facility

Source Name	Source ID	Annual	Units	Parameter	Factor	Emissions Units	Reference	Annual Emissions (tons/y)
No. 1 B&W Boiler Coal	S-B1	376882	klbs steam - coal	CO_2	267	lbs/klb steam	40CFR98 Subpart C Table C-1	50314
		376882	klbs steam - coal	CH_4	0.03	lbs/klb steam	40CFR98 Subpart C Table C-2	5.7
		376882	klbs steam - coal	N_2O	0.0044	lbs/klb steam	40CFR98 Subpart C Table C-2	0.8
							Total	50320
No. 1 B&W Boiler - Natural Gas	S-B1	8,817	klbs steam - gas	CO_2	145	lbs/klb steam	40CFR98 Subpart C Table C-1	639
		8,817	klbs steam - gas	CH_4	0.0028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.01
		8,817	klbs steam - gas	N_2O	0.00028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.001
							Total	639

Source Name	Source ID	Annual	Units	Parameter	Factor	Emissions Units	Reference	Annual Emissions (tons/y)
No. 2 B&W Boiler Coal	S-B2	425405	klbs steam - coal	CO_2	267	lbs/klb steam	40CFR98 Subpart C Table C-1	56792
		425405	klbs steam - coal	CH_4	0.03	lbs/klb steam	40CFR98 Subpart C Table C-2	6.4
		425405	klbs steam - coal	N_2O	0.0044	lbs/klb steam	40CFR98 Subpart C Table C-2	0.9
							Total	56799
No. 2 B&W Boiler Natural Gas	S-B2	12,320	klbs steam - gas	CO_2	145	lbs/klb steam	40CFR98 Subpart C Table C-1	893
		12,320	klbs steam - gas	CH_4	0.0028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.02
		12,320	klbs steam - gas	N_2O	0.00028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.002
							Total	893

B&W Boiler Natural Gas Conversion Project
GHG Emissions Estimates
Future Projected Emissions (Natural Gas)
The Amalgamated Sugar Co. LLC
Nampa Facility

Source Name	Source ID	Annual	Units	Parameter	Factor	Emissions Units	Reference	Annual Emissions (tons/y)
B&W No. 1 Boiler - Natural Gas	S-B1	919,800	klbs steam - gas	CO_2	145	lbs/klb steam	40CFR98 Subpart C Table C-1	66686
		919,800	klbs steam - gas	CH_4	0.0028	lbs/klb steam	40CFR98 Subpart C Table C-2	1.3
		919,800	klbs steam - gas	N_2O	0.00028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.13
							Total	66687
B&W No.2 Boiler - Natural Gas	S-B2	919,800	klbs steam - gas	CO_2	145	lbs/klb steam	40CFR98 Subpart C Table C-1	66686
		919,800	klbs steam - gas	CH_4	0.0028	lbs/klb steam	40CFR98 Subpart C Table C-2	1.3
		919,800	klbs steam - gas	N_2O	0.00028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.13
							Total	66687

Section 5.2.3
No. 1 & No. 2 B&W Boilers – TAPs & HAPs

No. 1 & No. 2 B&W Boilers Natural Gas Only Project
HAPs & TAPs Emissions Estimates
Nampa Facility

	B&W Boiler - Baseline							B&W Boiler - Projected						Total						
	Coal			Natural Gas				Coal			Natural Gas									
	EF	Annual Emissions	Hourly Emissions	EF	Annual Emissions	Hourly Emissions	Total Hourly Emissions	EF	Annual Emissions	Hourly Emissions	EF	Annual Emissions	Hourly Emissions	Total Hourly Emissions	Net Change Hourly Emissions	TAPs Screening Level (lb/h)	Exceeds Screening Level?	AAC (mg/m3)	Modeled[3] Conc	Exceeds AAC or AACC?
Non Carcinogens	lbs/klb	lbs/y	lbs/h	lbs/klb	lbs/y	lbs/h		lbs/klb	lbs/y	lbs/h	lbs/klb	lbs/y	lbs/h							
Acetophenone	9.91E-07	7.95E-01	2.1E-04				2.1E-04	9.91E-07	0.00E+00	0.0E+00				0.00E+00	-2.08E-04	none	No	none		
Acrolein	1.92E-05	1.54E+01	4.0E-03				4.0E-03	1.92E-05	0.00E+00	0.0E+00				0.00E+00	-4.02E-03	0.017	No	0.0125		
Antimony	1.19E-06	9.54E-01	2.5E-04				2.5E-04	1.19E-06	0.00E+00	0.0E+00				0.00E+00	-2.50E-04	0.033	No	0.025		
Barium	2.54E-03		5.3E-01	5.64E-06	1.19E-01	1.18E-03	5.3E-01	2.54E-03			5.64E-06	1.04E+01	1.18E-03	1.18E-03	-5.33E-01	0.033	No	0.025		
Benzyl Chloride	4.63E-05	3.71E+01	9.7E-03				9.7E-03	4.63E-05	0.00E+00	0.0E+00				0.00E+00	-9.71E-03	none	No	none		
Carbon Disulfide	8.59E-06	6.89E+00	1.8E-03				1.8E-03	8.59E-06	0.00E+00	0.0E+00				0.00E+00	-1.80E-03	2	No	1.5		
2-Chloroacetophenone	4.63E-07	3.71E-01	9.7E-05				9.7E-05	4.63E-07	0.00E+00	0.0E+00				0.00E+00	-9.71E-05	0.021	No	0.016		
Chlorobenzene	1.45E-06	1.17E+00	3.1E-04				3.1E-04	1.45E-06	0.00E+00	0.0E+00				0.00E+00	-3.05E-04	23.3	No	17.5		
Chromium (total)	1.72E-05	1.38E+01	3.6E-03	1.79E-06	3.79E-02	3.77E-04	4.0E-03	1.72E-05	0.00E+00	0.0E+00	1.79E-06	3.30E+00	3.77E-04	3.77E-04	-3.61E-03	0.033	No	0.025		
Cobalt	6.61E-06	5.30E+00	1.4E-03	1.08E-07	2.28E-03	2.26E-05	1.4E-03	6.61E-06	0.00E+00	0.0E+00	1.08E-07	1.98E-01	2.26E-05	2.26E-05	-1.39E-03	0.0033	No	0.0025		
Cumene	3.50E-07	2.81E-01	7.4E-05				7.4E-05	3.50E-07	0.00E+00	0.0E+00				0.00E+00	-7.36E-05	1.63E+01	No	12.25		
Cyanide	1.65E-04	1.33E+02	3.5E-02				3.5E-02	1.65E-04	0.00E+00	0.0E+00				0.00E+00	-3.47E-02	3.33E-01	No	0.25		
Dichlorobenzene	0.00E+00		0.0E+00	1.54E-06	3.25E-02	3.23E-04	3.2E-04	0.00E+00			1.54E-06	2.83E+00	3.23E-04	3.23E-04	0.00E+00	3.00E+01	No	15		
2,4-Dinitrotoluene	1.85E-08	1.48E-02	3.9E-06				3.9E-06	1.85E-08	0.00E+00	0.0E+00				0.00E+00	-3.89E-06	none	No	none		
Dimethyl Sulfate	3.17E-06	2.54E+00	6.7E-04				6.7E-04	3.17E-06	0.00E+00	0.0E+00				0.00E+00	-6.66E-04	none	No	none		
Ethyl Benzene	6.21E-06	4.98E+00	1.3E-03				1.3E-03	6.21E-06	0.00E+00	0.0E+00				0.00E+00	-1.30E-03	29	No	21.75		
Ethyl Chloride	2.78E-06	2.23E+00	5.8E-04				5.8E-04	2.78E-06	0.00E+00	0.0E+00				0.00E+00	-5.83E-04	176	No	132		
Ehtylene Dichloride	2.64E-06	2.12E+00	5.6E-04				5.6E-04	2.64E-06	0.00E+00	0.0E+00				0.00E+00	-5.55E-04	2.667	No	2		
Fluorides, as F	3.97E-04	3.18E+02	8.3E-02				8.3E-02	3.97E-04	0.00E+00	0.0E+00				0.00E+00	-8.33E-02	0.167	No	0.125		
Hexane	4.43E-06	3.55E+00	9.3E-04	2.31E-03	4.88E+01	4.85E-01	4.9E-01	4.43E-06	0.00E+00	0.0E+00	2.31E-03	4.25E+03	4.85E-01	4.85E-01	-9.30E-04	12	No	9		
Hydrogen Chloride	1.24E-03	9.91E+02	2.6E-01				2.6E-01	1.24E-03	0.00E+00	0.0E+00				0.00E+00	-2.60E-01	0.05	No	0.375		
Hydrogen Fluoride	4.65E-03		9.8E-01				9.8E-01	4.65E-03		0.0E+00				0.00E+00	-9.77E-01	none		none		
Isophorone	3.83E-05	3.08E+01	8.0E-03				8.0E-03	3.83E-05	0.00E+00	0.0E+00				0.00E+00	-8.05E-03	1.867	No	1.4		
Lead	2.78E-05	2.23E+01	5.8E-03	6.41E-07	1.35E-02	1.35E-04	6.0E-03	2.78E-05	0.00E+00	0.0E+00	6.41E-07	1.18E+00	1.35E-04	1.35E-04	-5.83E-03	none	No	none		
Magnesium	7.27E-04	5.83E+02	1.5E-01				1.5E-01	7.27E-04	0.00E+00	0.0E+00				0.00E+00	-1.53E-01	0.667	No	0.5		
Manganese	3.24E-05	2.60E+01	6.8E-03	4.87E-07	1.03E-02	1.02E-04	6.9E-03	3.24E-05	0.00E+00	0.0E+00	4.87E-07	8.96E-01	1.02E-04	1.02E-04	-6.80E-03	0.333	No	0.25		
Mercury	5.49E-06	4.40E+00	1.2E-03	3.33E-07	7.05E-03	7.00E-05	1.2E-03	5.49E-06	0.00E+00	0.0E+00	3.33E-07	6.13E-01	7.00E-05	7.00E-05	-1.15E-03	none	No	none		
Methyl Bromide	1.06E-05	8.48E+00	2.2E-03				2.2E-03	1.06E-05	0.00E+00	0.0E+00				0.00E+00	-2.22E-03	1.27	No	0.95		
Methyl Chloride	3.50E-05	2.81E+01	7.4E-03				7.4E-03	3.50E-05	0.00E+00	0.0E+00				0.00E+00	-7.36E-03	6.867	No	5.15		
Methyl Ethyl Ketone	2.58E-05	2.07E+01	5.4E-03				5.4E-03	2.58E-05	0.00E+00	0.0E+00				0.00E+00	-5.41E-03	39.3	No	29.5		
Methyl Methacylate	1.32E-06	1.06E+00	2.8E-04				2.8E-04	1.32E-06	0.00E+00	0.0E+00				0.00E+00	-2.78E-04	27.3	No	20.5		
Methyl Tert Butyl Ether	2.31E-06	1.86E+00	4.9E-04				4.9E-04	2.31E-06	0.00E+00	0.0E+00				0.00E+00	-4.86E-04	none	No	none		
Napthalene	0.00E+00	0.00E+00	0.0E+00				0.0E+00	0.00E+00	0.00E+00	0.0E+00				0.00E+00	0.00E+00	3.33	No	2.5		
Pentane	0.00E+00		0.0E+00	3.33E-03	7.05E+01	7.00E-01	7.0E-01	0.00E+00			3.33E-03	6.13E+03	7.00E-01	7.00E-01	0.00E+00	118	No	88.5		
Phenol	1.06E-06	8.48E-01	2.2E-04				2.2E-04	1.06E-06	0.00E+00	0.0E+00				0.00E+00	-2.22E-04	1.27	No	0.95		
Propionaldehyde	2.51E-05	2.01E+01	5.3E-03				5.3E-03	2.51E-05	0.00E+00	0.0E+00				0.00E+00	-5.27E-03	0.0287	No	0.0215		
Selenium	8.59E-05	6.89E+01	1.8E-02	3.08E-08	6.50E-04	6.46E-06	1.8E-02	8.59E-05	0.00E+00	0.0E+00	3.08E-08	5.66E-02	6.46E-06	6.46E-06	-1.80E-02	0.013	No	0.01		
Styrene	1.65E-06	1.33E+00	3.5E-04				3.5E-04	1.65E-06	0.00E+00	0.0E+00				0.00E+00	-3.47E-04	6.67E+00	No	1		
Sulfuric Acid	2.27E-02	1.82E+04	4.8E+00				4.8E+00	2.27E-02	0.00E+00	0.0E+00				0.00E+00	-4.77E+00		No			
Toluene	1.59E-05	1.27E+01	3.3E-03	4.36E-06	9.21E-02	9.15E-04	4.2E-03	1.59E-05	0.00E+00	0.0E+00	4.36E-06	8.02E+00	9.15E-04	9.15E-04	-3.33E-03	25	No	18.75		
Xylene (total)	2.45E-06	1.96E+00	5.1E-04				5.1E-04	2.45E-06	0.00E+00	0.0E+00				0.00E+00	-5.13E-04	29	No	21.75		
Vinyl Acetate	5.02E-07	4.03E-01	1.1E-04				1.1E-04	5.02E-07	0.00E+00	0.0E+00				0.00E+00	-1.05E-04	none	No	none		
Compounds - Carcinogens																		AACC (ug/m^3)		
Acetaldehyde	3.77E-05	3.02E+01	7.9E-03				7.9E-03	3.77E-05	0.00E+00	0.0E+00				0.00E+00	-7.91E-03	3.00E-03	No	4.50E-01		
Arsenic Compounds	2.71E-05	2.17E+01	5.7E-03	2.56E-07	5.42E-03	5.38E-05	5.7E-03	2.71E-05	0.00E+00	0.0E+00	2.56E-07	4.72E-01	5.38E-05	5.38E-05	-5.69E-03	1.50E-06	No	2.30E-04		
Benzene	8.59E-05	6.89E+01	1.8E-02	2.69E-06	5.69E-02	5.65E-04	1.9E-02	8.59E-05	0.00E+00	0.0E+00	2.69E-06	4.95E+00	5.65E-04	5.65E-04	-1.80E-02	8.00E-04	No	1.20E-01		
Beryllium Compounds	1.39E-06	1.11E+00	2.9E-04	1.54E-08	3.25E-04	3.23E-06	2.9E-04	1.39E-06	0.00E+00	0.0E+00	1.54E-08	2.83E-02	3.23E-06	3.23E-06	-2.91E-04	2.80E-05	No	4.20E-03		
Bis (2-ethylhexyl) phthalate	4.82E-06	3.87E+00	1.0E-03				1.0E-03	4.82E-06	0.00E+00	0.0E+00				0.00E+00	-1.01E-03	2.80E-02	No	4.20E+00		
Cadmium Compounds	3.37E-06	2.70E+00	7.1E-04	1.41E-06	2.98E-02	2.96E-04	1.0E-03	3.37E-06	0.00E+00	0.0E+00	1.41E-06	2.59E+00	2.96E-04	2.96E-04	-7.08E-04	3.70E-06	No	5.60E-04		
Chloroform	3.90E-06	3.13E+00	8.2E-04				8.2E-04	3.90E-06	0.00E+00	0.0E+00				0.00E+00	-8.19E-04	2.80E-04	No	4.30E-02		
Chromium 6+ Compounds	5.22E-06	4.19E+00	1.1E-03	1.79E-06	3.79E-02	3.77E-04	1.5E-03	5.22E-06	0.00E+00	0.0E+00	1.79E-06	3.30E+00	3.77E-04	3.77E-04	-1.10E-03	5.60E-07	No	8.30E-05		
Ethylene Dibromide	7.93E-08	6.36E-02	1.7E-05				1.7E-05	7.93E-08	0.00E+00	0.0E+00				0.00E+00	-1.67E-05	3.00E-05	No	4.50E-03		
Formaldehyde	1.59E-05	1.27E+01	3.3E-03	9.62E-05	2.03E+00	2.02E-02	2.4E-02	1.59E-05	0.00E+00	0.0E+00	9.62E-05	1.77E+02	2.02E-02	2.02E-02	-3.33E-03	5.10E-04	No	7.70E-02		
Methyl Hydrazine	1.12E-05	9.01E+00	2.4E-03				2.4E-03	1.12E-05	0.00E+00	0.0E+00				0.00E+00	-2.36E-03	2.20E-05	No	3.20E-03		
Methylene Chloride	1.92E-05	1.54E+01	4.0E-03				4.0E-03	1.92E-05	0.00E+00	0.0E+00				0.00E+00	-4.02E-03	1.60E-03	No	2.40E-01		
Nickel	1.85E-05	1.48E+01	3.9E-03	2.69E-06	5.69E-02	5.65E-04	4.5E-03	1.85E-05	0.00E+00	0.0E+00	2.69E-06	4.95E+00	5.65E-04	5.65E-04	-3.89E-03	2.70E-05	No	4.20E-03		
PAHs	1.37E-06	1.10E+00	2.9E-04				2.9E-04	1.37E-06	0.00E+00	0.0E+00				0.00E+00	-2.89E-04	9.10E-05	No	1.40E-02		
POM				1.07E-07	2.25E-03	2.24E-05	2.2E-05				1.07E-07	1.96E-01	2.24E-05	2.24E-05	0.00E+00	9.10E-05	No			
Tetrachloroethylene	2.84E-06	2.28E+00	6.0E-04				6.0E-04	2.84E-06	0.00E+00	0.0E+00				0.00E+00	-5.97E-04	1.30E-02	No			
1,1,1 - Trichloroethane	1.32E-06	1.06E+00	2.8E-04				2.8E-04	1.32E-06	0.00E+00	0.0E+00				0.00E+00	-2.78E-04	4.20E-04	No			

2006/2007 Baseline

Source	Material	Units	Max Hourly	Annual
B&W Boiler - Coal	Steam	klbs	210	802,287
B&W Boiler - Nat. Gas	Steam	klbs	210	21,137

Projected

Source	Material	Units	Max Hourly	Annual
B&W Boiler - Coal	Steam	klbs	0	0
B&W Boiler(Gas)	Steam	klbs	210	1,839,600

AAC : Acceptable Ambient Concentrations for non-carcinogens (IDAPA 58.01.01.585)
AACC : Acceptable Ambient Concentrations for Carcinogens (IDAPA 58.01.01.586)

B&W Boiler
Estimated TAP's Emissions Factors
Coal Combustion (lbs per klb steam)
Nampa Facility

Non Carcinogens	Type	Reference	Type	Uncontrolled EF (lbs/ton coal)	Controlled EF (lbs/klbs steam)
Acetophenone	HAP	a	VOC	1.50E-05	9.91E-07
Acrolein	HAP/TAP	a	VOC	2.90E-04	1.92E-05
Antimony	TAP	b	Trace Metal	1.80E-05	1.19E-06
Barium	TAP	c	Trace Metal	3.84E-02	2.54E-03
Benzyl Chloride	HAP	a	VOC	7.00E-04	4.63E-05
Carbon Disulfide	HAP/TAP	a	VOC	1.30E-04	8.59E-06
2-Chloroacetophenone	HAP/TAP	a	VOC	7.00E-06	4.63E-07
Chlorobenzene	HAP/TAP	a	VOC	2.20E-05	1.45E-06
Chromium (total)	HAP/TAP	b	Trace Metal	2.60E-04	1.72E-05
Cobalt	HAP/TAP	b	Trace Metal	1.00E-04	6.61E-06
Cumene	HAP/TAP	b	Trace Metal	5.30E-06	3.50E-07
Cyanide	HAP/TAP			2.50E-03	1.65E-04
2,4-Dinitrotoluene	HAP	a	VOC	2.80E-07	1.85E-08
Dimethyl Sulfate	HAP	a	VOC	4.80E-05	3.17E-06
Ethyl Benzene	HAP/TAP	a	VOC	9.40E-05	6.21E-06
Ethyl Chloride	HAP/TAP	a	VOC	4.20E-05	2.78E-06
Ethylene Dichloride	HAP/TAP	a	VOC	4.00E-05	2.64E-06
Flourides, as F	TAP	d		6.00E-03	3.97E-04
Hexane	HAP/TAP	a	VOC	6.70E-05	4.43E-06
Hydrogen Chloride	HAP/TAP	d		1.87E-02	1.24E-03
Hydrogen Fluoride	HAP	d		7.04E-02	4.65E-03
Isophorone	HAP/TAP	a	VOC	5.80E-04	3.83E-05
Lead	HAP	b	Trace Metal	4.20E-04	2.78E-05
Magnesium	NA	b	Trace Metal	1.10E-02	7.27E-04
Manganese	HAP/TAP	b	Trace Metal	4.90E-04	3.24E-05
Mercury	HAP	b	Trace Metal	8.30E-05	5.49E-06
Methyl Bromide	HAP/TAP	a	VOC	1.60E-04	1.06E-05
Methyl Chloride	HAP/TAP	a	VOC	5.30E-04	3.50E-05
Methyl Ethyl Ketone	HAP/TAP	a	VOC	3.90E-04	2.58E-05
Methyl Methacylate	HAP/TAP	a	VOC	2.00E-05	1.32E-06
Methyl Tert Butyl Ether	HAP	a	VOC	3.50E-05	2.31E-06
Napthalene is included in the PAH factors.					
Phenol	HAP/TAP	a	VOC	1.60E-05	1.06E-06
Propionaldehyde	HAP/TAP	a	VOC	3.80E-04	2.51E-05
Selenium	HAP/TAP	b	Trace Metal	1.30E-03	8.59E-05
Styrene	HAP/TAP	a	VOC	2.50E-05	1.65E-06
Sulfuric Acid	TAP	e		3.44E-01	2.27E-02
Toluene	HAP/TAP	a	VOC	2.40E-04	1.59E-05
Xylene (total)	HAP	a	VOC	3.70E-05	2.45E-06
Vinyl Acetate	HAP/TAP	a	VOC	7.60E-06	5.02E-07
Compounds - Carcinogens					
Acetaldehyde	HAP/TAP	a	VOC	5.70E-04	3.77E-05
Arsenic Compounds	HAP/TAP	b	Trace Metal	4.10E-04	2.71E-05
Benzene	HAP/TAP	a	VOC	1.30E-03	8.59E-05
Beryllium Compounds	HAP/TAP	b	Trace Metal	2.10E-05	1.39E-06
Bis(2-ethylhexyl)phthalate	HAP/TAP	a	VOC	7.30E-05	4.82E-06
Cadmium Compounds	HAP/TAP	b	Trace Metal	5.10E-05	3.37E-06
Chloroform	HAP/TAP	a	VOC	5.90E-05	3.90E-06
Chromium 6+ compounds	HAP/TAP	b	Trace Metal	7.90E-05	5.22E-06
Ethylene Dibromide	HAP	a	VOC	1.20E-06	7.93E-08
Formaldehyde	HAP/TAP	a	VOC	2.40E-04	1.59E-05
Methyl Hydrazine	HAP/TAP	a	VOC	1.70E-04	1.12E-05
Methylene Chloride	HAP/TAP	a	VOC	2.90E-04	1.92E-05
Nickel	HAP/TAP	b	Trace Metal	2.80E-04	1.85E-05
PAHs	TAP	f	VOC	2.08E-05	1.37E-06
POMs in coal do not have an AP 42 factor. They are represented by PAHs					
Tetrachloroethylene	HAP/TAP	a	VOC	4.30E-05	2.84E-06
1,1,1 - Trichloroethane	HAP/TAP	a	VOC	2.00E-05	1.32E-06
				Total (Coal) EF	**3.31E-02**

a. AP-42, Table 1.1-14 Emissions Factors for Various Organic Compounds from Controlled Combustion
b. AP-42, Table 1.1-18 Emissions Factors for Trace Metals from Controlled Combustion
c Mass balance, USGS data and 80% emissions control.
d. Title V Permit Application & USGS Data
e. Eng. Stack Test
f. AP-42, Table 1.1-13 Emissions Factors for Polynuclear Aromatic Hydrocarbons (PAH)

Boiler
Estimated TAP's Emissions Factors
Natural Gas Combustion (lbs per klb steam)
Nampa Facility

Non Carcinogens	Type	Reference	Type	EF (lbs/MMcuft)	EF (lbs/klbs steam)
Barium	TAP	a	Trace Metal	4.40E-03	5.64E-06
Chromium (total)	HAP/TAP	a	Trace Metal	1.40E-03	1.79E-06
Cobalt	HAP/TAP	a	Trace Metal	8.40E-05	1.08E-07
Dichlorobenzene	TAP	b	VOC	1.20E-03	1.54E-06
Hexane	HAP/TAP	b	VOC	1.80E+00	2.31E-03
Lead	HAP	c	Trace Metal	5.00E-04	6.41E-07
Manganese	HAP/TAP	a	Trace Metal	3.80E-04	4.87E-07
Mercury	HAP	a	Trace Metal	2.60E-04	3.33E-07
Naphthalene	HAP/TAP	b	VOC	6.10E-04	7.82E-07
Pentane	TAP	b	VOC	2.60E+00	3.33E-03
Selenium	HAP/TAP	a	Trace Metal	2.40E-05	3.08E-08
Toluene	HAP/TAP	b	VOC	3.40E-03	4.36E-06
Compounds - Carcinogens					
Arsenic Compounds	HAP/TAP	a	Trace Metal	2.00E-04	2.56E-07
Benzene	HAP/TAP	b	VOC	2.10E-03	2.69E-06
Beryllium Compounds	HAP/TAP	a	Trace Metal	1.20E-05	1.54E-08
Cadmium Compounds	HAP/TAP	a	Trace Metal	1.10E-03	1.41E-06
Chromium 6+ compounds	HAP/TAP	a	Trace Metal	1.40E-03	1.79E-06
Formaldehyde	HAP/TAP	b	VOC	7.50E-02	9.62E-05
Nickel	HAP/TAP	a	Trace Metal	2.10E-03	2.69E-06
PAHs are not listed in AP42 for natural gas,					
POM	TAP	b	VOC	8.32E-05	1.07E-07
				Total (Natural Gas) EF	**5.76E-03**

a. AP-42, Table 1.4-4 Emissions Factors for Metals from Natural Gas Combustion
b. AP-42, Table 1.4-3 Emissions Factors for Speciated Organic Compounds from Natural Gas
b. AP-42, Table 1.4-2 Emissions Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion

Section 5.3.1
Elimination of Coal-Fired Pulp Dryers

Emissions Reduction Project
Elimination of 3 Coal Fired Pulp Dryers[a]
The Amalgamated Sugar Co. LLC
Nampa Facility

Sources	PM[a] (lbs/h)	PM[a] (tons/y)	NOx (lbs/h)	NOx (tons/y)	SO2 (lbs/h)	SO2 (tons/y)	CO (lbs/h)	CO (tons/y)	VOC (lbs/h)	VOC (tons/y)	All Criteria (lbs/h)	All Criteria (tons/y)
Pulp Dryers	-65.2	-80	-160	-196	-15.2	-18.6	-598.7	-728	-3.67	-4.46	-843	-1027

[a] Based on 2005 emissions estimates

Coal Fired Pulp Dryers - 2005 Emissions Estimates
The Amalgamated Sugar Co. LLC
Nampa Facility

Source Name	Source ID	Production Max Hourly	Production Daily	Production Annual	Parameter	Factor	Emissions Units	Reference	Emissions (lbs/h)	Emissions (tons/y)
South Pulp Dryer	S-D1	65	43	103,912	PM & PM10	0.62	lbs/ton input	Stack test Nov. 2002	26.5	32.2
		65	43	103,912	NOx	1.58	lbs/ton input	2001 Eng. Stack Test	67.5	82.1
		65	43	103,912	SO2	0.15	lbs/ton input	2001 Eng. Stack Test	6.4	7.8
		65	43	103,912	CO	5.87	lbs/ton input	2001 Eng. Stack Test	252.4	305.0
		65	43	103,912	VOC	0.036	lbs/ton input	Source Test/Eng. Test	1.5	1.87
Center Pulp Dryer	S-D2	65	43	103,912	PM & PM10	0.58	lbs/ton input	Stack test Dec 2003	24.8	30.1
		65	43	103,912	NOx	1.58	lbs/ton input	2001 Eng. Stack Test	67.5	82.1
		65	43	103,912	SO2	0.15	lbs/ton input	2001 Eng. Stack Test	6.4	7.8
		65	43	103,912	CO	5.87	lbs/ton input	2001 Eng. Stack Test	252.4	305.0
		65	43	103,912	VOC	0.036	lbs/ton input	Source Test/Eng. Test	1.5	1.87
North Pulp Dryer	S-D3	24	16	40,176	PM & PM10	0.87	lbs/ton input	Stack test Nov. 2002	13.9	17.5
		24	16	40,176	NOx	1.58	lbs/ton input	2001 Eng. Stack Test	25.3	31.7
		24	16	40,176	SO2	0.15	lbs/ton input	2001 Eng. Stack Test	2.4	3.0
		24	16	40,176	CO	5.87	lbs/ton input	2001 Eng. Stack Test	93.9	117.9
		24	16	40,176	VOC	0.036	lbs/ton input	Source Test/Eng. Test	0.6	0.72

		(lbs/h)	(tons/y)
Total	PM & PM10	65.2	79.8
	NOx	160.2	195.9
	SO2	15.2	18.6
	CO	598.7	727.9
	VOC	3.7	4.5
	All Criteria	843.0	1026.7

Section 5.3.2
Riley Boiler Low NO_x Burner Project

NO_x Emssions Reductions
BART Low NO_x Burner Project
Riley Boiler
Nampa Facility

Parameter	Value
Current[a]	
• Emissions (lbs/h)	374
• Steam (Klbs/h)	227
• NO_x EF (lbs/Klb steam)	1.53
Future with LNB's[b]	
• Emissions (lbs/h)	147
• Steam (Klbs/h)	250
• NO_x EF (lbs/Klb steam)	0.59
Net Reductions	
• Emissions (lbs/h)	-227
• % Reduction	60.7

[a] 2009 Stack Test

[b] BART Tier II Permit (T2-2009.0105)

SUMMARY OF CRITERIA POLLUTANT ACTUAL FACILITY EMISSIONS
2006 & 2007 Crop Year Average vs. Future
Nampa Facility

Year	PM10	SO2	CO	NOx	VOC	Production Summary: Days		Steam (klbs steam)				
						Beet	Juice	Total	Coal	%	Gas	%
Baseline 2006/2007	169	2374	2241	1963	73	131	234	2583480	2429717	94.0%	153763	6.0%
Future	113	1617	2258	975	77	160	205	4555200	1882500	41.3%	2672700	58.7%
Net	-56	-757	17	-988	4	29	-29	1971720	-547217		2518937	

SUMMARY OF CRITERIA POLLUTANT ACTUAL FACILITY EMISSIONS
1979 & 1980 Crop Year Average vs. Future
Nampa Facility

Year	PM10	SO2	CO	NOx	VOC	Production Summary: Days		Steam (klbs steam)				
						Beet	Juice	Total	Coal	%	Gas	%
Baseline 1979/1980	159	1638	1912	1607	50	117	132	1798634	1655968	92.1%	142666	7.9%
Future	113	1617	2258	975	77	160	205	4555200	1882500	41.3%	2672700	58.7%
Net	-46	-21	346	-632	27	43	73	2756566	226532		2530034	

Section 5.4.1
Facility Baseline Emissions (2006-2007)

11/12/2015

SUMMARY OF CRITERIA POLLUTANT EMISSIONS
Nampa Facility - 2006/2007

Table I

Source	ID	PM max lbs/hr	PM avg lbs/h	PM year tns/yr	PM10 max lbs/hr	PM10 avg lbs/h	PM10 year tns/yr	SO2 max lbs/hr	SO2 avg lbs/h	SO2 year tns/yr	CO max lbs/hr	CO avg lbs/h	CO year tns/yr	NOx max lbs/hr	NOx avg lbs/h	NOx year tns/yr	VOC max lbs/hr	VOC avg lbs/h	VOC year tns/yr
B&W Boiler No. 1	S-B1	5.0	2.1	9.2	5.0	2.1	9.2	189.0	77.4	339.2	15.4	6.4	28.1	115.5	47.7	208.8	0.4	0.2	0.8
B&W Boiler No. 2	S-B2	5.0	2.4	10.4	5.0	2.4	10.4	189.0	87.4	382.9	15.4	7.3	31.9	115.5	53.9	236.0	0.4	0.2	0.9
Riley Boiler	S-B3	14.3	10.7	46.8	12.4	9.3	40.8	500.0	371.6	1627.4	0.6	0.8	3.5	382.5	296.7	1299.7	2.0	1.5	6.5
Union Boiler	S-B4	1.6	0.3	1.4	1.6	0.3	1.4	0.04	0.01	0.0	6.6	1.3	5.8	7.2	1.4	6.3	0.4	0.1	0.4
South Pulp Dryer	S-D1	29.7	7.4	32.2	29.7	7.4	32.2	7.2	1.8	7.8	281.2	69.6	305.0	75.7	18.7	82.1	1.7	0.4	1.9
Center Pulp Dryer	S-D2	27.8	6.9	30.1	27.8	6.9	30.1	7.2	1.8	7.8	281.2	69.6	305.0	75.7	18.7	82.1	1.7	0.4	1.9
North Pulp Dryer	S-D3	24.4	4.0	17.4	24.4	4.0	17.4	4.2	0.7	3.0	164.4	26.8	117.4	44.2	7.2	31.6	1.0	0.2	0.7
Pellet Cooler Baghouse	S-D9	0.80	0.80	3.50	0.80	0.80	3.50												
Lime Kiln A	S-K1	0.89	0.24	1.04	0.891	0.237	1.04	0.34	0.09	0.41	549.5	145.9	638.9	6.24	1.66	7.25	0.489	0.137	0.598
Lime Kiln B	S-K2	1.04	0.30	1.31	1.035	0.298	1.31	0.39	0.12	0.52	638.3	183.9	805.4	7.25	2.09	9.14	0.565	0.173	0.760
Lime Kiln Material Handling	S-K3	1.10	0.33	1.46	1.10	0.33	1.46												
A & B Process Slakers	S-K4	1.40	1.39	6.10	1.40	1.39	6.10												
Drying Granulator	S-W1	1.10	1.14	5.00	1.10	1.14	5.00												
#1 Cooling Granulator	S-W2	0.30	0.30	1.30	0.30	0.30	1.30												
#2 Cooling Granulator	S-W3	0.30	0.30	1.30	0.30	0.30	1.30												
Sugar Handling(Process)	S-W4	0.30	0.27	1.20	0.30	0.27	1.20												
Sugar Handling(Specialties)	S-W6	0.10	0.14	0.60	0.10	0.14	0.60												
Sugar Handling(Pack Line)	S-W7	0.20	0.21	0.90	0.20	0.21	0.90												
Main Mill	S-O1																49.9	13.4	58.6
A Side Sulfur Stove	S-O2							2.1	0.6	2.7									
B Side Sulfur Stove	S-O3							2.1	0.6	2.7									
Coal Unloading (Railcar)@Dryer	FD9					0.00E+00	0.00E+00												
Pulp&Pellet Storage and Loadout	FD10					3.36E-03	1.47E-02												
Coal Unloading (Railcar)	FO4					7.56E-04	3.31E-03												
Coal Storage/Loading	FO5O6					0.41	1.79												
Beet Hauling	FO7					0.28	1.21												
Vehicle Traffic on Unpaved Roads	FO8					0.11	0.49												
Lime Rock Handling	FO9					0.15	0.68												
Coke Handling	FO10					0.05	0.20												
TOTAL	TOTAL	115.3	39.1	171.1	113.4	38.7	169.5	901.6	542.1	2374.4	1952.5	511.7	2241.0	829.8	448.2	1963.0	58.7	16.7	73.1

SECTION 3B. PRODUCTION DATA - BOILER HOUSE

NO.		MATERIAL	UNITS	Max Hr	Avg Hr	ANNUAL
S-B1	B & W BOILER NO. 1	Steam (Coal)-Beet	1000 lbs	105.0	95.0	293,928
		Coal (1)-Beet	Tons	6.4	6.4	15,636
		Steam (Natural Gas)-Beet	1000 lbs	0.0	0.0	5,146
		Natural Gas (1)-Beet	MMcf	0.0	0.0	6
		Steam (Coal)-Juice	1000 lbs	0.0	0.0	82,954
		Coal (1)-Juice	Tons	0.0	0.0	4,482
		Steam (Natural Gas)-Juice	1000 lbs	0.0	0.0	3,671
		Natural Gas (1)-Juice	MMcf	0.0	0.0	4.1
S-B2	B & W BOILER NO. 2	Steam (Coal)-Beet	1000 lbs	105.0	95.0	294,996
		Coal (1)-Beet	Tons	6.4	6.4	15,656
		Steam (Natural Gas)-Beet	1000 lbs	0.0	0.0	4,696
		Natural Gas (1)-Beet	MMcf	0.0	0.0	4.9
		Steam (Coal)-Juice	1000 lbs	0.0	0.0	130,409
		Coal (1)-Juice	Tons	0.0	0.0	6,999
		Steam (Natural Gas)-Juice	1000 lbs	0.0	0.0	7,624
		Natural Gas (1)-Juice	MMcf	0.0	0.0	8.2
S-B3	RILEY BOILER	Steam (Coal)-Beet	1000 lbs	250.0	230.0	731,725
		Coal (1)-Beet	Tons	18.0	18.0	46,090
		Steam (Natural Gas)-Beet	1000 lbs	0.0	0.0	15,744
		Natural Gas (1)-Beet	MMcf	0.0	0.0	21
		Steam (Coal)-Juice	1000 lbs	250.0	221.0	895,707
		Coal (1)-Juice	Tons	0.0	0.0	57,348
		Steam (Natural Gas)-Juice	1000 lbs	0.0	0.0	11,630
		Natural Gas (1)-Juice	MMcf	0.0	0.0	14.7
S-B4	UNION BOILER	Steam (Natural Gas)-Beet	1000 lbs	60.0	52.0	96,038
		Natural Gas (1)-Beet	MMcf	0.085	0.085	133
		Steam (Natural Gas)-Juice	1000 lbs	0.0	0	9,215
		Natural Gas (1)-Juice	MMcf	0.0	0	12

Beet run	**131**	**3144 hrs.**
Juice Run	**193**	**4632 hrs.**
Separator	**45**	**1080 hrs.**
Totals	**369**	**8856 hrs.**

Total Steam(klbs)		2,583,483
Beet Steam (klbs)	55.83%	1,442,273
Juice Steam(klbs)	44.17%	1,141,210
Coal Steam (klbs)	94.05%	2,429,719
Gas Steam(klbs)	5.95%	153,764

SECTION 3C. EMISSION FACTORS - BOILER HOUSE

NO.		POLLUTANT	UNIT	EMISSION FACTOR (1) LB/UNIT	REFERENCE
S-B1	B & W BOILER NO.1 - STEAM(coal)	PM	1000 lbs	0.048	Bolier MACT Limit (0.04 lb/MMBtu)
		PM10	1000 lbs	0.048	Assume PM10 is equivalent to PM
		SO2	1000 lbs	1.80	AP-42, 9/98, Table 1.4-1, 0.8%S
		CO	1000 lbs	0.147	Eng. Stack Test Oct 2009
		NOx	1000 lbs	1.100	Eng. Stack Test Oct 2009
		VOC	1000 lbs	0.0042	AP-42, 9/98, Table 1.4-1
	B & W BOILER NO.1 - STEAM (gas)	PM	1000 lbs	2.60E-02	IDAPA 58.01.01.677 (0.015 gr/dscf grain loading std.)
		PM10	1000 lbs	2.60E-02	Assume PM10 is equivalent to PM
		SO2	1000 lbs	7.20E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.00E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	3.36E-01	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	6.60E-03	AP-42, 9/98, Table 1.4-2
S-B2	B & W BOILER NO.2 - STEAM(coal)	PM	1000 lbs	0.048	Bolier MACT Limit (0.04 lb/MMBtu)
		PM10	1000 lbs	0.048	Assume PM10 is equivalent to PM
		SO2	1000 lbs	1.80	AP-42, 9/98, Table 1.4-1, 0.8%S
		CO	1000 lbs	0.15	Eng. Stack Test Oct 2009
		NOx	1000 lbs	1.100	Eng. Stack Test Oct 2009
		VOC	1000 lbs	0.0042	AP-42, 9/98, Table 1.4-1
	B & W BOILER NO.2 - STEAM (gas)	PM	1000 lbs	2.60E-02	IDAPA 58.01.01.677 (0.015 gr/dscf grain loading std.)
		PM10	1000 lbs	2.60E-02	Assume PM10 is equivalent to PM
		SO2	1000 lbs	7.20E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.00E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	3.36E-01	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	6.60E-03	AP-42, 9/98, Table 1.4-2
S-B3	RILEY BOILER - STEAM(coal)	PM	1000 lbs	0.057	Bolier MACT Limit (0.04 lb/MMBtu)
		PM10	1000 lbs	0.0496	Tier II BART Permit Limit (12.4 lbs/h)
		SO2	1000 lbs	2.00	AP-42, 9/98, Table 1.4-1, 0.8%S
		CO	1000 lbs	2.33E-03	Eng. Stack Test Oct 2009
		NOx	1000 lbs	1.53	Eng. Stack Test Oct 2009
		VOC	1000 lbs	0.0079	AP-42, 9/98, Table 1.4-1
	RILEY BOILER - STEAM (gas)	PM	1000 lbs	3.00E-02	IDAPA 58.01.01.677 (0.015 gr/dscf grain loading std.)
		PM10	1000 lbs	3.00E-02	Assume PM10 is equivalent to PM
		SO2	1000 lbs	8.60E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.20E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	4.00E+00	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	7.90E-03	AP-42, 9/98, Table 1.4-2
S-B4	UNION BOILER - STEAM (gas)	PM	1000 lbs	2.60E-02	IDAPA 58.01.01.677 (0.015 gr/dscf grain loading std.)
		PM10	1000 lbs	2.60E-02	Assume PM10 is equivalent to PM
		SO2	1000 lbs	7.20E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.10E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	1.20E-01	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	7.40E-03	AP-42, 7/98, Table 1.4-2

SECTION 3D. EMISSIONS - BOILER HOUSE

Based on campaign length (days) = 131

NO.		POLLUTANT	Max lb/hr	Avg. lbs./hr.	TONS/YR
S-B1	B & W BOILER NO. 1 (Beet)	PM	5.0	4.6	7.1
		PM10	5.0	4.6	7.1
		SO2	189.0	171.0	264.5
		CO	15.4	14.0	21.9
		NOx	115.5	104.5	162.5
		VOC	0.44	0.40	0.63
	B & W BOILER NO. 1 (Juice)	PM	0.0	0.0	2.0
		PM10	0.0	0.0	2.0
		SO2	0.0	0.0	74.7
		CO	0.0	0.0	6.3
		NOx	0.0	0.0	46.2
		VOC	0.0	0.0	0.2
S-B2	B & W BOILER NO. 2 (Beet)	PM	5.0	4.6	7.1
		PM10	5.0	4.6	7.1
		SO2	189.0	171.0	265.5
		CO	15.4	14.0	21.9
		NOx	115.5	104.5	163.0
		VOC	0.44	0.40	0.63
	B & W BOILER NO. 2 (Juice)	PM	0.0	0.0	3.2
		PM10	0.0	0.0	3.2
		SO2	0.0	0.0	117.4
		CO	0.0	0.0	10.0
		NOx	0.0	0.0	73.0
		VOC	0.0	0.0	0.3
S-B3	RILEY BOILER (Beet)	PM	14.3	13.1	21
		PM10	12.4	11.4	18
		SO2	500.0	460.0	732
		CO	0.6	0.5	2
		NOx	382.5	351.9	591
		VOC	2.0	1.8	3
	RILEY BOILER (Juice)	PM	14.3	12.6	26
		PM10	12.4	11.0	22
		SO2	500.0	442.0	896
		CO	0.6	0.5	2
		NOx	382.5	338.1	708
		VOC	2.0	1.7	4
S-B4	UNION BOILER (Beet)	PM	1.6	1.4	1
		PM10	1.6	1.4	1
		SO2	0.0	0.0	0
		CO	6.6	5.72	5
		NOx	7.2	6.2	6
		VOC	0.4	0.4	0
	UNION BOILER (Juice)	PM	0.0	0.0	0
		PM10	0.0	0.0	0
		SO2	0.0	0.0	0
		CO	0.0	0.0	1
		NOx	0.0	0.0	1
		VOC	0.0	0.0	0

SECTION 3B. PRODUCTION DATA - PULP DRYING AND PELLETIZING

2005

NO.		MATERIAL	UNITS	Max Hrly	Avg Hrly	ANNUAL
S-D1	SOUTH DRYER	Total Input (1)	Tons	47.9	42.7	103912
		Coal (2)	Tons	4.0	3.9	9385
		Natural Gas (3)	MMcf	0.100	0.100	345
S-D2	CENTER DRYER	Total Input (1)	Tons	47.9	42.7	103912
		Coal (2)	Tons	4.0	3.9	9385
		Natural Gas (3)	MMcf	0.100	0.100	345
S-D3	NORTH DRYER	Total Input (1)	Tons	28.0	16.4	40000
		Coal (2)	Tons	2.4	1.5	3606
		Natural Gas (3)	MMcf	0.100	0.100	345
S-D9	PELLET BAGHOUSE	Hrs. operation	hr.	0.8	0.8	7008
						7008

(1) Total input includes press pulp, coal, and additives.
(2) Production data assumes that only coal is used to dry pulp.

Est days of campaign	**101**
Est. hours of operation	**2424**

SECTION 3C. EMISSION FACTORS - PULP DRYING AND PELLETIZING

NO.		POLLUTANT	UNIT	EMISSION FACTOR (1) LB/UNIT	REFERENCE
S-D1	SOUTH DRYER -TOTAL INPUT	PM	Tons	0.62	Nov. 2002 Stack Test
		PM10	Tons	0.62	Nov. 2002 Stack Test
		CO	Tons	5.87	2001 Eng. Stack Test
		SO2	Tons	0.15	2001 Eng. Stack Test
		NOx	Tons	1.58	2001 Eng. Stack Test
		VOC	Tons	0.036	Source Test / Eng. test

NO.		POLLUTANT	UNIT	EMISSION FACTOR (1) LB/UNIT	REFERENCE
S-D2	CENTER DRYER -TOTAL INPUT	PM	Tons	0.58	Nov. 2002 Stack Test
		PM10	Tons	0.58	Nov. 2002 Stack Test
		CO	Tons	5.87	2001 Eng. Stack Test
		SO2	Tons	0.15	2001 Eng. Stack Test
		NOx	Tons	1.58	2001 Eng. Stack Test
		VOC	Tons	0.036	Source Test / Eng. test

NO.		POLLUTANT	UNIT	EMISSION FACTOR (1) LB/UNIT	REFERENCE
S-D3	NORTH DRYER -TOTAL INPUT	PM	Tons	0.87	Nov. 2002 Stack Test
		PM10	Tons	0.87	Nov. 2002 Stack Test
		CO	Tons	5.87	2001 Eng. Stack Test
		SO2	Tons	0.15	2001 Eng. Stack Test
		NOx	Tons	1.58	2001 Eng. Stack Test
		VOC	Tons	0.036	Source Test / Eng. test

SECTION 3C. EMISSION FACTORS - PULP DRYING AND PELLETIZING

NO.		POLLUTANT	UNIT	EMISSION FACTOR (1) LB/UNIT	REFERENCE
S-D9	PELLET MILL BAGHOUSE	PM	lbs./ hr.	0.80	Current Tier I Permit Limit, Condition 6.1
		PM10	lbs./ hr.	0.80	(limit 0.8 lbs./hr. & 3.1 tons/yr.)

SECTION 3D. EMISSIONS - PULP DRYING AND PELLETIZING

NO.		POLLUTANT	Max lb/hr	Avg. lbs./hr.	TONS/YR
S-D1	SOUTH DRYER	PM	29.70	26.47	32.21
		PM10	29.70	26.47	32.21
		CO	281.17	250.65	304.98
		SO2	7.19	6.41	7.79
		NOx	75.68	67.47	82.09
		VOC	1.72	1.54	1.87
S-D2	CENTER DRYER	PM	27.78	24.77	30.13
		PM10	27.78	24.77	30.13
		CO	281.17	24.77	304.98
		SO2	7.19	24.77	7.79
		NOx	75.68	67.47	82.09
		VOC	1.72	1.54	1.87
S-D3	NORTH DRYER	PM	24.36	14.27	17.40
		PM10	24.36	14.27	17.40
		CO	164.36	96.27	117.40
		SO2	4.20	2.46	3.00
		NOx	44.24	25.91	31.60
		VOC	1.01	0.59	0.72
S-D9	PELLET MILL BAGHOUSE	PM	0.80	0.80	3.50
		PM10	0.80	0.80	3.50

SECTION 3B. PRODUCTION DATA - LIME KILN AND CO2 PRODUCTION

NO.		MATERIAL	UNITS	Max Hrly	Avg Hrly	ANNUAL
S-K1	A LIME KILN	Lime Rock	Tons	9.9	7.4	23,025
		Coke	Tons	0.84	0.66	2,055
S-K2	B LIME KILN	Lime Rock	Tons	11.5	9.3	29,023
		Coke	Tons	0.97	0.83	2,610
S-K3	LIME KILN MATERIAL HANDLING	MATERIAL	Tons	21.4	17.9	56,713
S-K4	A&B PROCESS SLAKERS	CaO	Tons	10.7	9.3	29,147

SECTION 3C. EMISSION FACTORS - LIME KILN AND CO2 PRODUCTION

NO.		POLLUTANT	EMISSION FACTOR (1) UNIT	LB/UNIT	REFERENCE
S-K1	A LIME KILN				
	- LIME ROCK	PM	Tons	0.0900	12/03 Source Test
		PM10	Tons	0.0900	12/03 Source Test
		CO	Tons	55.5	Eng. Stack Test Dec 2003
		NOx	Tons	0.63	AP-42 Table 1.2-1, anthracite coal
	- COKE	SO2	Tons	0.4	Ap-42 Table 1.4-2 & 99% removal
		VOC	Tons	0.5820	Eng. est based on 2005 stack test
S-K2	B LIME KILN				
	- LIME ROCK	PM	Tons	0.0900	12/03 Source Test
		PM10	Tons	0.0900	12/03 Source Test
		CO	Tons	55.5	Eng. Stack Test Dec 2003
		NOx	Tons	0.63	AP-42 Table 1.2-1, anthracite coal
	-COKE	SO2	Tons	0.4	Ap-42 Table 1.4-2 & 99% removal
		VOC	Tons	0.5820	Eng. est based on 2005 stack test
S-K3	LIME KILN MATERIAL HANDLING BAGHOUSE	PM	Tons	0.0514	Source test, Nov-05
	- MATERIAL HANDLED	PM10	Tons	0.0514	Source test, Nov-05
S-K4	PROCESS SLAKERS	PM	lbs/h	1.4	Tier I & Tier II Permit Limit
	-CaO	PM10	lbs/h	1.4	Tier I & Tier II Permit Limit

SECTION 3D. EMISSIONS - LIME KILN AND CO2 PRODUCTION

NO.		POLLUTANT	Max lbs./hr.	Avg. lbs./hr.	TONS/YR
S-K1	A LIME KILN	PM	0.89	0.67	1.04
		PM10	0.89	0.67	1.04
		SO2	0.34	0.26	0.4
		CO	549	411	639
		NOx	6.24	4.66	7.3
		VOC	0.49	0.38	0.60
S-K2	B LIME KILN	PM	1.04	0.84	1.31
		PM10	1.04	0.84	1.31
		SO2	0.39	0.33	0.5
		CO	638	516.2	805.4
		NOx	7.25	5.86	9.14
		VOC	0.56	0.48	0.76
S-K3	LIME KILN MATERIAL HANDLING BAGHOUSE	PM	1.10	0.92	1.46
		PM10	1.10	0.92	1.46
S-K4	PROCESS SLAKERS	PM	1.40	1.40	6.10
		PM10	1.40	1.40	6.10

(1) Hourly production data cannot be determined, because of a batch process with significant hourly variability.

SECTION 3B. PRODUCTION DATA - SUGAR WAREHOUSE AND SHIPPING

NO.		MATERIAL	UNITS	Max hrly	Hourly	ANNUAL
S-W1	DRYING GRANULATOR	Sugar	Tons	55.0	41.4	129,505
S-W2	NO. 1 COOLING GRANULATOR	Sugar	Tons	27.5	21.4	66,850
S-W3	NO. 2 COOLING GRANULATOR	Sugar	Tons	27.5	21.4	66,850
S-W4	SUGAR HANDLING (PROCESS #2)	NA	Hours	1.0	1.0	7200
S-W6	SUGAR HANDLING (SPECIALTIES)	NA	Hours	1.0	1.0	7200
S-W7	SUGAR HANDLING (PACK. LINE)	NA	Hours	1.0	1.0	7200

SECTION 3C. EMISSION FACTORS - SUGAR WAREHOUSE AND SHIPPING

NO.		POLLUTANT	EMISSION FACTOR (1) UNIT	LB/UNIT	REFERENCE
S-W1	DRYING GRANULATOR - SUGAR	PM	lbs/h	1.1	Tier I & Tier II Permit Limit
		PM10	lbs/h	1.1	Tier I & Tier II Permit Limit
S-W2	NO. 1 COOLING GRANULATOR - SUGAR	PM	lbs/h	0.3	Tier I & Tier II Permit Limit
		PM10	lbs/h	0.3	Tier I & Tier II Permit Limit
S-W3	NO. 2 COOLING GRANULATOR - SUGAR	PM	lbs/h	0.3	Tier I & Tier II Permit Limit
		PM10	lbs/h	0.3	Tier I & Tier II Permit Limit
S-W4	SUGAR HANDLING (PROCESS #2)	PM	lbs/h	0.3	Tier I & Tier II Permit Limit
		PM10	lbs/h	0.3	Tier I & Tier II Permit Limit
S-W6	SUGAR HANDLING (SPECIALTIES)	PM	lbs/h	0.1	Tier I & Tier II Permit Limit
		PM10	lbs/h	0.1	Tier I & Tier II Permit Limit
S-W7	SUGAR HANDLING (PACK. LINE)	PM	lbs/h	0.2	Tier I & Tier II Permit Limit
		PM10	lbs/h	0.2	Tier I & Tier II Permit Limit

(1) See Appendix G for emission factor documentation.

SECTION 3D. EMISSIONS - SUGAR WAREHOUSE AND SHIPPING

NO.		POLLUTANT	Max lbs./hr.	Avg. lbs./hr.	TONS/YR
S-W1	DRYING GRANULATOR - SUGAR (tons)	PM	1.10	1.10	5.00
		PM10	1.10	1.10	5.00
S-W2	NO. 1 COOLING GRANULATOR - SUGAR	PM	0.30	0.30	1.30
		PM10	0.30	0.30	1.30
S-W3	NO. 2 COOLING GRANULATOR - SUGAR	PM	0.30	0.30	1.30
		PM10	0.30	0.30	1.30
S-W4	SUGAR HANDLING (PROCESS #2)	PM	0.30	0.30	1.20
		PM10	0.30	0.30	1.20
S-W6	SUGAR HANDLING (SPECIALTIES)	PM	0.10	0.10	0.60
		PM10	0.10	0.10	0.60
S-W7	SUGAR HANDLING (PACK. LINE)	PM	0.20	0.20	0.90
		PM10	0.20	0.20	0.90

SECTION 3B. PRODUCTION DATA - OTHER SOURCES

NO.		MATERIAL	UNITS	Max Hrly	Avg Hrly	ANNUAL
S-O5	MAIN MILL	Thin Juice	1000 gal	109.0	98	274436
S-O2	A - SIDE SULFUR STOVE	Sulfur	Tons	0.021	0.013	78
S-O3	B - SIDE SULFUR STOVE	Sulfur	Tons	0.021	0.013	78

(1) Assume max hourly rates are 15 % above average rates.
(2) Estimating thin juice flow from diffuser operation in 2002-03 campaign of 273 gal./ton beets.

SECTION 3C. EMISSION FACTORS - OTHER SOURCES

NO.		POLLUTANT	UNIT	EMISSION FACTOR (1) LB/UNIT	REFERENCE
S-O5	MAIN MILL	VOC	1000 gal	0.277	Nonvalidated Source Test Method
S-O2	A - SIDE SULFUR STOVE	SO2	lb/ton	101.64	July 1992 Eng Stack Test @ Nampa , 20% safety factor
S-O3	B - SIDE SULFUR STOVE	SO2	lb/ton	101.64	July 1992 Eng Stack Test @ Nampa , 20% safety factor

(1) See Appendix G for emission factor documentation.

SECTION 3D. EMISSIONS - OTHER SOURCES

NO.		POLLUTANT	Max lbs/h	Avg lbs/hr	tons/y
S-O5	MAIN MILL	VOC	30.2	27.1	38.0
S-O2	A - SIDE SULFUR STOVE	SO2	2.1	1.3	3.9
S-O3	B - SIDE SULFUR STOVE	SO2	2.1	1.3	3.9

(1) Hourly production data cannot be determined, because of a batch process with significant hourly variability.
(2) Hourly averages on fugitive sources are calculated by dividing production by hours of beet campaign.

Section 5.4.2
Facility Baseline Emissions (1979-1980)

SUMMARY OF CRITERIA POLLUTANT EMISSIONS - Avg 1979/1980 Emissions
Nampa Facility - Annual Emissions

Table I

		PM			PM10			SO2			CO			NOx			VOC		
Source	ID	max lbs/hr	avg lbs/h	year tns/yr	max lbs/hr	avg lbs/h	year tns/yr	max lbs/hr	avg lbs/h	year tns/yr	max lbs/hr	avg lbs/h	year tns/yr	max lbs/hr	avg lbs/h	year tns/yr	max lbs/hr	avg lbs/h	year tns/yr
B&W Boiler No. 1	S-B1	5.0	1.4	5.9	5.0	1.4	5.9	189.0	48.5	212.3	15.4	4.2	18.4	115.5	30.4	133.2	0.4	0.1	0.6
B&W Boiler No. 2	S-B2	5.0	1.4	5.9	5.0	1.4	5.9	189.0	48.5	212.3	15.4	4.2	18.4	115.5	30.4	133.2	0.4	0.1	0.6
Riley Boiler	S-B3	14.3	8.1	35.3	12.4	7.1	30.9	500.0	270.4	1184.2	0.6	1.7	7.5	382.5	253.4	1109.9	2.0	1.2	5.1
Union Boiler	S-B4	1.6	0.0	0.0	1.6	0.0	0.0	0.04	0.00	0.0	6.6	0.0	0.0	7.2	0.0	0.0	0.4	0.0	0.0
South Pulp Dryer	S-D1	40.3	8.2	36.0	40.3	8.2	36.0	9.8	2.0	8.7	381.6	77.8	340.6	102.7	20.9	91.7	2.3	0.5	2.1
Center Pulp Dryer	S-D2	37.7	7.7	33.6	37.7	7.7	33.6	9.8	2.0	8.7	381.6	77.8	340.6	102.7	20.9	91.7	2.3	0.5	2.1
North Pulp Dryer	S-D3	21.8	4.4	19.5	21.8	4.4	19.5	3.8	0.8	3.4	146.8	30.0	131.3	39.5	8.1	35.3	0.9	0.2	0.8
Pellet Cooler Baghouse	S-D9	0.80	0.80	3.50	0.80	0.80	3.50												
Lime Kiln A	S-K1	0.89	0.18	0.79	0.891	0.181	0.79	0.34	0.06	0.28	550.4	111.8	489.7	6.24	1.27	5.55	0.489	0.093	0.409
Lime Kiln B	S-K2	1.04	0.21	0.92	1.035	0.210	0.92	0.39	0.08	0.34	639.4	129.5	567.4	7.25	1.47	6.43	0.565	0.113	0.496
Lime Kiln Material Handling	S-K3	1.74	0.36	1.56	1.74	0.36	1.56												
A & B Process Slakers	S-K4	1.40	1.39	6.10	1.40	1.39	6.10												
Drying Granulator	S-W1	1.10	1.14	5.00	1.10	1.14	5.00												
#1 Cooling Granulator	S-W2	0.30	0.30	1.30	0.30	0.30	1.30												
#2 Cooling Granulator	S-W3	0.30	0.30	1.30	0.30	0.30	1.30												
Sugar Handling(Process)	S-W4	0.30	0.27	1.20	0.30	0.27	1.20												
Sugar Handling(Specialties)	S-W6	0.10	0.14	0.60	0.10	0.14	0.60												
Sugar Handling(Pack Line)	S-W7	0.20	0.21	0.90	0.20	0.21	0.90												
Main Mill	S-O1																30.2	27.1	38.0
Side Sulfur Stove	S-O2							2.1	1.3	3.9									
Side Sulfur Stove	S-O3							2.1	1.3	3.9									
Coal Unloading (Railcar)@Dryer	FD9					0.00E+00	0.00E+00												
Pulp&Pellet Storage and Loadout	FD10					3.36E-03	1.47E-02												
Coal Unloading (Railcar)	FO4					7.56E-04	3.31E-03												
Coal Storage/Loading	FO5O6					0.41	1.79												
Beet Hauling	FO7					0.28	1.21												
Vehicle Traffic on Unpaved Roads	FO8					0.11	0.49												
Lime Rock Handling	FO9					0.15	0.68												
Coke Handling	FO10					0.05	0.20												
TOTAL	TOTAL	133.8	36.4	159.4	132.0	36.4	159.4	906.3	374.8	1638.1	2137.7	436.9	1913.8	879.1	366.9	1606.9	40.1	29.9	50.1

SECTION 3B. PRODUCTION DATA - BOILER HOUSE

NO.		MATERIAL	UNITS	Max Hr	Avg Hr	ANNUAL
S-B1	B & W BOILER NO. 1	Steam (Coal)-Beet	1000 lbs	105.0	98.0	235,912
		Coal (1)-Beet	Tons			
		Steam (Natural Gas)-Beet	1000 lbs	0.0	0.0	20,326
		Natural Gas (1)-Beet	MMcf	0.0	0.0	0
		Steam (Coal)-Juice	1000 lbs	0.0	0.0	0
		Coal (1)-Juice	Tons	0.0	0.0	0
		Steam (Natural Gas)-Juice	1000 lbs	0.0	0.0	0
		Natural Gas (1)-Juice	MMcf	0.0	0.0	0
S-B2	B & W BOILER NO. 2	Steam (Coal)-Beet	1000 lbs	105.0	85.0	235,912
		Coal (1)-Beet	Tons			
		Steam (Natural Gas)-Beet	1000 lbs	0.0	0.0	20,326
		Natural Gas (1)-Beet	MMcf	0.0	0.0	0
		Steam (Coal)-Juice	1000 lbs	0.0	0.0	0
		Coal (1)-Juice	Tons	0.0	0.0	0
		Steam (Natural Gas)-Juice	1000 lbs	0.0	0.0	0
		Natural Gas (1)-Juice	MMcf	0.0	0.0	0
S-B3	RILEY BOILER	Steam (Coal)-Beet	1000 lbs	250.0	233.0	561,182
		Coal (1)-Beet	Tons			
		Steam (Natural Gas)-Beet	1000 lbs	0.0	0.0	48,346
		Natural Gas (1)-Beet	MMcf	0.0	0.0	0
		Steam (Coal)-Juice	1000 lbs	250.0	233.0	622,963
		Coal (1)-Juice	Tons	0.0	0.0	0
		Steam (Natural Gas)-Juice	1000 lbs	0.0	0.0	53,669
		Natural Gas (1)-Juice	MMcf	0.0	0.0	0
S-B4	UNION BOILER	Steam (Natural Gas)-Beet	1000 lbs	60.0	52.0	0
		Natural Gas (1)-Beet	MMcf	0.000	0.000	0
		Steam (Natural Gas)-Juice	1000 lbs	0.0	0	0
		Natural Gas (1)-Juice	MMcf	0.0	0	0

Beet run	**117**	**2808**	**hrs.**
Juice Run (testout/cleanup[5])	**132**	**3168**	**hrs.**
Totals	**249**	**5976**	**hrs.**

Total Steam(klbs)		1,798,636
Beet Steam (klbs)	62.38%	1,122,004
Juice Steam(klbs)	37.62%	676,632
Coal Steam (klbs)	92.07%	1,655,969
Gas Steam(klbs)	7.93%	142,667

SECTION 3C. EMISSION FACTORS - BOILER HOUSE

NO.		POLLUTANT	UNIT	EMISSION FACTOR (1) LB/UNIT	REFERENCE
S-B1	B & W BOILER NO.1 - STEAM(coal)	PM	1000 lbs	0.048	Bolier MACT Limit (0.04 lb/MMBtu)
		PM10	1000 lbs	0.048	Assume PM10 is equivalent to PM
		SO2	1000 lbs	1.80	AP-42, 9/98, Table 1.4-1, 0.8%S
		CO	1000 lbs	0.147	Eng. Stack Test Oct 2009
		NOx	1000 lbs	1.100	Eng. Stack Test Oct 2009
		VOC	1000 lbs	0.0042	AP-42, 9/98, Table 1.4-1
	B & W BOILER NO.1 - STEAM (gas)	PM	1000 lbs	2.60E-02	IDAPA 58.01.01.677 (0.015 gr/dscf grain loading std.)
		PM10	1000 lbs	2.60E-02	Assume PM10 is equivalent to PM
		SO2	1000 lbs	7.20E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.00E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	3.36E-01	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	6.60E-03	AP-42, 9/98, Table 1.4-2
S-B2	B & W BOILER NO.2 - STEAM(coal)	PM	1000 lbs	0.048	Bolier MACT Limit (0.04 lb/MMBtu)
		PM10	1000 lbs	0.048	Assume PM10 is equivalent to PM
		SO2	1000 lbs	1.80	AP-42, 9/98, Table 1.4-1, 0.8%S
		CO	1000 lbs	0.15	Eng. Stack Test Oct 2009
		NOx	1000 lbs	1.100	Eng. Stack Test Oct 2009
		VOC	1000 lbs	0.0042	AP-42, 9/98, Table 1.4-1
	B & W BOILER NO.2 - STEAM (gas)	PM	1000 lbs	2.60E-02	IDAPA 58.01.01.677 (0.015 gr/dscf grain loading std.)
		PM10	1000 lbs	2.60E-02	Assume PM10 is equivalent to PM
		SO2	1000 lbs	7.20E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.00E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	3.36E-01	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	6.60E-03	AP-42, 9/98, Table 1.4-2
S-B3	RILEY BOILER - STEAM(coal)	PM	1000 lbs	0.057	Bolier MACT Limit (0.04 lb/MMBtu)
		PM10	1000 lbs	0.0496	Tier II BART Permit Limit (12.4 lbs/h)
		SO2	1000 lbs	2.00	AP-42, 9/98, Table 1.4-1, 0.8%S
		CO	1000 lbs	2.33E-03	Eng. Stack Test Oct 2009
		NOx	1000 lbs	1.53	Eng. Stack Test Oct 2009
		VOC	1000 lbs	0.0079	AP-42, 9/98, Table 1.4-1
	RILEY BOILER - STEAM (gas)	PM	1000 lbs	3.00E-02	IDAPA 58.01.01.677 (0.015 gr/dscf grain loading std.)
		PM10	1000 lbs	3.00E-02	Assume PM10 is equivalent to PM
		SO2	1000 lbs	8.60E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.20E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	4.00E+00	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	7.90E-03	AP-42, 9/98, Table 1.4-2
S-B4	UNION BOILER - STEAM (gas)	PM	1000 lbs	2.60E-02	IDAPA 58.01.01.677 (0.015 gr/dscf grain loading std.)
		PM10	1000 lbs	2.60E-02	Assume PM10 is equivalent to PM
		SO2	1000 lbs	7.20E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.10E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	1.20E-01	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	7.40E-03	AP-42, 7/98, Table 1.4-2

SECTION 3D. EMISSIONS - BOILER HOUSE

Based on campaign length (days) = 117

NO.		POLLUTANT	Max lb/hr	Avg. lbs./hr.	TONS/YR
S-B1	B & W BOILER NO. 1 (Beet)	PM	5.0	4.7	5.9
		PM10	5.0	4.7	5.9
		SO2	189.0	176.4	212.3
		CO	15.4	14.4	18.4
		NOx	115.5	107.8	133.2
		VOC	0.44	0.41	0.56
	B & W BOILER NO. 1 (Juice)	PM	0.0	0.0	0.0
		PM10	0.0	0.0	0.0
		SO2	0.0	0.0	0.0
		CO	0.0	0.0	0.0
		NOx	0.0	0.0	0.0
		VOC	0.0	0.0	0.0
S-B2	B & W BOILER NO. 2 (Beet)	PM	5.0	4.1	5.9
		PM10	5.0	4.1	5.9
		SO2	189.0	153.0	212.3
		CO	15.4	12.5	18.4
		NOx	115.5	93.5	133.2
		VOC	0.44	0.36	0.56
	B & W BOILER NO. 2 (Juice)	PM	0.0	0.0	0.0
		PM10	0.0	0.0	0.0
		SO2	0.0	0.0	0.0
		CO	0.0	0.0	0.0
		NOx	0.0	0.0	0.0
		VOC	0.0	0.0	0.0
S-B3	RILEY BOILER (Beet)	PM	14.3	13.3	17
		PM10	12.4	11.6	15
		SO2	500.0	466.0	561
		CO	0.6	0.5	4
		NOx	382.5	356.5	526
		VOC	2.0	1.8	2
	RILEY BOILER (Juice)	PM	14.3	13.3	19
		PM10	12.4	11.6	16
		SO2	500.0	466.0	623
		CO	0.6	0.5	4
		NOx	382.5	356.5	584
		VOC	2.0	1.8	3
S-B4	UNION BOILER (Beet)	PM	1.6	1.4	0
		PM10	1.6	1.4	0
		SO2	0.0	0.0	0
		CO	6.6	5.72	0
		NOx	7.2	6.2	0
		VOC	0.4	0.4	0
	UNION BOILER (Juice)	PM	0.0	0.0	0
		PM10	0.0	0.0	0
		SO2	0.0	0.0	0
		CO	0.0	0.0	0
		NOx	0.0	0.0	0
		VOC	0.0	0.0	0

SECTION 3B. PRODUCTION DATA - PULP DRYING AND PELLETIZING

NO.		MATERIAL	UNITS	Max Hrly	Avg Hrly	ANNUAL
S-D1	SOUTH DRYER	Total Input (1)	Tons	65.0	41.5	116034
		Coal (2)	Tons	7.0	4.5	12582
		Natural Gas (3)	MMcf	0.140	0.089	250
S-D2	CENTER DRYER	Total Input (1)	Tons	65.0	41.5	116034
		Coal (2)	Tons	7.0	4.5	12582
		Natural Gas (3)	MMcf	0.140	0.089	250
S-D3	NORTH DRYER	Total Input (1)	Tons	25.0	16.0	44736
		Coal (2)	Tons	2.7	1.7	4753
		Natural Gas (3)	MMcf	0.054	0.035	97
S-D9	PELLET COOLERS	Hrs. operation	tons	35.2	22.4	62360
						7008

(1) Total input includes press pulp, coal, and additives.
(2) Production data assumes that only coal is used to dry pulp.

Beet campaign	**117**
Hours of operation	**2808**

SECTION 3C. EMISSION FACTORS - PULP DRYING AND PELLETIZING

NO.		POLLUTANT	UNIT	EMISSION FACTOR (1) LB/UNIT	REFERENCE
S-D1	SOUTH DRYER -TOTAL INPUT	PM	Tons	0.62	Source Test Nov. 2002
		PM10	Tons	0.62	Source Test Nov. 2002
		CO	Tons	5.87	2001 Eng. Stack Test
		SO2	Tons	0.15	2001 Eng. Stack Test
		NOx	Tons	1.58	2001 Eng. Stack Test
		VOC	Tons	0.036	Source Test / Eng. test
	- COAL	Lead	Tons	4.20E-04	EPA AP-42,Table 1.1-18
		Fluorine	Tons	6.34E-03	Mass balance based on USGS data
		Beryllium	Tons	2.10E-05	EPA AP-42,Table 1.1-18
		Mercury	Tons	7.00E-05	Mass balance based on USGS data
		H2SO4	Tons	5.00E-02	EPA AP-42,Table 1.1-3, footnote b.

NO.		POLLUTANT	UNIT	EMISSION FACTOR (1) LB/UNIT	REFERENCE
S-D2	CENTER DRYER -TOTAL INPUT	PM	Tons	0.58	Source Test Dec. 2003
		PM10	Tons	0.58	Source Test Dec. 2003
		CO	Tons	5.87	2001 Eng. Stack Test
		SO2	Tons	0.15	2001 Eng. Stack Test
		NOx	Tons	1.58	2001 Eng. Stack Test
		VOC	Tons	0.036	Source Test / Eng. test
	- COAL	Lead	Tons	4.20E-04	EPA AP-42,Table 1.1-18
		Fluorine	Tons	6.34E-03	Mass balance based on USGS data
		Beryllium	Tons	2.10E-05	EPA AP-42,Table 1.1-18
		Mercury	Tons	7.00E-05	Mass balance based on USGS data
		H2SO4	Tons	5.00E-02	EPA AP-42,Table 1.1-3, footnote b.

NO.		POLLUTANT	UNIT	EMISSION FACTOR (1) LB/UNIT	REFERENCE
S-D3	NORTH DRYER -TOTAL INPUT	PM	Tons	0.87	Source Test Nov. 2002
		PM10	Tons	0.87	Source Test Nov. 2002
		CO	Tons	5.87	2001 Eng. Stack Test
		SO2	Tons	0.15	2001 Eng. Stack Test
		NOx	Tons	1.58	2001 Eng. Stack Test
		VOC	Tons	0.036	Source Test / Eng. test
	- COAL	Lead	Tons	4.20E-04	EPA AP-42,Table 1.1-18
		Fluorine	Tons	6.34E-03	Mass balance based on USGS data
		Beryllium	Tons	2.10E-05	EPA AP-42,Table 1.1-18
		Mercury	Tons	7.00E-05	Mass balance based on USGS data
		H2SO4	Tons	5.00E-02	EPA AP-42,Table 1.1-3, footnote b.

SECTION 3C. EMISSION FACTORS - PULP DRYING AND PELLETIZING

NO.		POLLUTANT	UNIT	EMISSION FACTOR (1) LB/UNIT	REFERENCE
S-D9	PELLET MILL BAGHOUSE	PM	lbs./ hr.	0.80	Current Tier I Permit Limit, Condition 6.1
		PM10	lbs./ hr.	0.80	(limit 0.8 lbs./hr. & 3.1 tons/yr.)

SECTION 3D. EMISSIONS - PULP DRYING AND PELLETIZING

NO.		POLLUTANT	Max lb/hr	Avg. lbs./hr.	TONS/YR
S-D1	SOUTH DRYER	PM	40.3	25.73	35.97
		PM10	40.3	25.73	35.97
		CO	381.55	243.605	340.56
		SO2	9.75	6.225	8.70
		NOx	102.7	65.57	91.67
		VOC	2.34	1.494	2.09
		Lead	2.94E-03	1.89E-03	0.00
		Fluorine	4.44E-02	2.85E-02	0.04
		Beryllium	1.47E-04	9.45E-05	0.00
		Mercury	4.90E-04	3.15E-04	0.00
		H2SO4	3.50E-01	2.25E-01	0.31
S-D2	CENTER DRYER	PM	37.70	24.07	33.65
		PM10	37.70	24.07	33.65
		CO	381.55	243.61	340.56
		SO2	9.75	6.23	8.70
		NOx	102.70	65.57	91.67
		VOC	2.34	1.49	2.09
		Lead	2.94E-03	1.89E-03	0.00
		Fluorine	4.44E-02	2.85E-02	0.04
		Beryllium	1.47E-04	9.45E-05	0.00
		Mercury	4.90E-04	3.15E-04	0.00
		H2SO4	3.50E-01	2.25E-01	0.31
S-D3	NORTH DRYER	PM	21.75	13.92	19.46
		PM10	21.75	13.92	19.46
		CO	146.75	93.92	131.30
		SO2	3.75	2.40	3.36
		NOx	39.50	25.28	35.34
		VOC	0.90	0.58	0.81
		Lead	1.13E-03	7.14E-04	0.00
		Fluorine	1.71E-02	1.08E-02	0.02
		Beryllium	5.67E-05	3.57E-05	0.00
		Mercury	1.89E-04	1.19E-04	0.00
		H2SO4	1.35E-01	8.50E-02	0.12
S-D9	PELLET MILL BAGHOUSE	PM	0.80	0.80	3.50
		PM10	0.80	0.80	3.50

(1) Hourly emissions cannot be calculated because hourly production cannot be determined.

SECTION 3B. PRODUCTION DATA - LIME KILN AND CO2 PRODUCTION

NO.		MATERIAL	UNITS	Max Hrly	Avg Hrly	ANNUAL
S-K1	A LIME KILN	Lime Rock	Tons	9.9	6.3	17,615
		Coke	Tons	0.84	0.50	1,406
S-K2	B LIME KILN	Lime Rock	Tons	11.5	7.3	20,411
		Coke	Tons	0.97	0.61	1,706
S-K3	LIME KILN MATERIAL HANDLING	MATERIAL	Tons	33.9	21.7	60,543
S-K4	A&B PROCESS SLAKERS	CaO	Tons	10.7	6.8	19,013

SECTION 3C. EMISSION FACTORS - LIME KILN AND CO2 PRODUCTION

NO.		POLLUTANT	EMISSION FACTOR (1) UNIT	EMISSION FACTOR (1) LB/UNIT	REFERENCE
S-K1	A LIME KILN				
	- LIME ROCK	PM	Tons	0.0900	12/03 Source Test
		PM10	Tons	0.0900	12/03 Source Test
		CO	Tons	55.6	Eng. Stack Test Dec 2003
		NOx	Tons	0.63	AP-42 Table 1.2-1, anthracite coal
	- COKE	SO2	Tons	0.4	AP-42 Table 1.4-2 & 99% removal
		VOC	Tons	0.5820	Eng. est based on 2005 stack test
S-K2	B LIME KILN				
	- LIME ROCK	PM	Tons	0.0900	12/03 Source Test
		PM10	Tons	0.0900	12/03 Source Test
		CO	Tons	55.6	Eng. Stack Test Dec 2003
		NOx	Tons	0.63	AP-42 Table 1.2-1, anthracite coal
	-COKE	SO2	Tons	0.4	AP-42 Table 1.4-2 & 99% removal
		VOC	Tons	0.5820	Eng. est based on 2005 stack test
S-K3	LIME KILN MATERIAL HANDLING BAGHOUSE	PM	Tons	0.0514	Source test, Nov-05
	- MATERIAL HANDLED	PM10	Tons	0.0514	Source test, Nov-05
S-K4	PROCESS SLAKERS	PM	Tons	1.4	Tier I & Tier II Permit Limit
	-CaO	PM10	Tons	1.4	Tier I & Tier II Permit Limit

SECTION 3D. EMISSIONS - LIME KILN AND CO2 PRODUCTION

NO.		POLLUTANT	Max lbs./hr.	Avg. lbs./hr.	TONS/YR
S-K1	A LIME KILN	PM	0.89	0.57	0.79
		PM10	0.89	0.57	0.79
		SO2	0.34	0.20	0.3
		CO	550	350	490
		NOx	6.24	3.97	5.5
		VOC	0.49	0.29	0.41
S-K2	B LIME KILN	PM	1.04	0.66	0.92
		PM10	1.04	0.66	0.92
		SO2	0.39	0.24	0.3
		CO	639	405.9	567.4
		NOx	7.25	4.60	6.43
		VOC	0.56	0.36	0.50
S-K3	LIME KILN MATERIAL HANDLING BAGHOUSE	PM	1.74	1.12	1.56
		PM10	1.74	1.12	1.56
S-K4	PROCESS SLAKERS	PM	1.40	1.40	6.10
		PM10	1.40	1.40	6.10

(1) Hourly production data cannot be determined, because of a batch process with significant hourly variability.

SECTION 3B. PRODUCTION DATA - SUGAR WAREHOUSE AND SHIPPING

NO.		MATERIAL	UNITS	Max hrly	Hourly	ANNUAL
S-W1	DRYING GRANULATOR	Sugar	Tons	35.3	35.3	210,529
S-W2	NO. 1 COOLING GRANULATOR	Sugar	Tons	35.3	35.3	210,529
S-W3	NO. 2 COOLING GRANULATOR	Sugar	Tons	0.0	0.0	-
S-W4	SUGAR HANDLING (PROCESS #2)	NA	Hours	1.0	1.0	5964
S-W6	SUGAR HANDLING (SPECIALTIES)	NA	Hours	1.0	1.0	5964
S-W7	SUGAR HANDLING (PACK. LINE)	NA	Hours	1.0	1.0	5964

1) Assume max hourly is 15% above average hourly.

SECTION 3C. EMISSION FACTORS - SUGAR WAREHOUSE AND SHIPPING

NO.		POLLUTANT	EMISSION FACTOR (1) UNIT	LB/UNIT	REFERENCE
S-W1	DRYING GRANULATOR				
	- SUGAR	PM	lbs/h	1.1	Tier I & Tier II Permit Limit
		PM10	lbs/h	1.1	Tier I & Tier II Permit Limit
S-W2	NO. 1 COOLING GRANULATOR	PM	lbs/h	0.3	Tier I & Tier II Permit Limit
	- SUGAR	PM10	lbs/h	0.3	Tier I & Tier II Permit Limit
S-W3	NO. 2 COOLING GRANULATOR				
	- SUGAR	PM	lbs/h	0.3	Tier I & Tier II Permit Limit
		PM10	lbs/h	0.3	Tier I & Tier II Permit Limit
S-W4	SUGAR HANDLING (PROCESS #2)	PM	lbs/h	0.3	Tier I & Tier II Permit Limit
		PM10	lbs/h	0.3	Tier I & Tier II Permit Limit
S-W6	SUGAR HANDLING (SPECIALTIES)	PM	lbs/h	0.1	Tier I & Tier II Permit Limit
		PM10	lbs/h	0.1	Tier I & Tier II Permit Limit
S-W7	SUGAR HANDLING (PACK. LINE)	PM	lbs/h	0.2	Tier I & Tier II Permit Limit
		PM10	lbs/h	0.2	Tier I & Tier II Permit Limit

SECTION 3D. EMISSIONS - SUGAR WAREHOUSE AND SHIPPING

NO.		POLLUTANT	Max lbs./hr.	Avg. lbs./hr.	TONS/YR
S-W1	DRYING GRANULATOR	PM	1.10	1.10	5.00
	- SUGAR (tons)	PM10	1.10	1.10	5.00
S-W2	NO. 1 COOLING GRANULATOR	PM	0.30	0.30	1.30
	- SUGAR	PM10	0.30	0.30	1.30
S-W3	NO. 2 COOLING GRANULATOR	PM	0.30	0.30	1.30
	- SUGAR	PM10	0.30	0.30	1.30
S-W4	SUGAR HANDLING (PROCESS #2)	PM	0.30	0.30	1.20
		PM10	0.30	0.30	1.20
S-W6	SUGAR HANDLING (SPECIALTIES)	PM	0.10	0.10	0.60
		PM10	0.10	0.10	0.60
S-W7	SUGAR HANDLING (PACK. LINE)	PM	0.20	0.20	0.90
		PM10	0.20	0.20	0.90

SECTION 3B. PRODUCTION DATA - OTHER SOURCES

NO.		MATERIAL	UNITS	Max Hrly	Avg Hrly	ANNUAL
S-O5	MAIN MILL	Thin Juice	1000 gal	109.0	98	274436
S-O2	A - SIDE SULFUR STOVE	Sulfur	Tons	0.021	0.013	78
S-O3	B - SIDE SULFUR STOVE	Sulfur	Tons	0.021	0.013	78

(1) Assume max hourly rates are 15 % above average rates.
(2) Estimating thin juice flow from diffuser operation in 2002-03 campaign of 273 gal./ton beets.

SECTION 3C. EMISSION FACTORS - OTHER SOURCES

NO.		POLLUTANT	UNIT	EMISSION FACTOR (1) LB/UNIT	REFERENCE
S-O5	MAIN MILL	VOC	1000 gal	0.277	Nonvalidated Source Test Method
S-O2	A - SIDE SULFUR STOVE	SO2	lb/ton	101.64	July 1992 Eng Stack Test @ Nampa , 20% safety factor
S-O3	B - SIDE SULFUR STOVE	SO2	lb/ton	101.64	July 1992 Eng Stack Test @ Nampa , 20% safety factor

(1) See Appendix G for emission factor documentation.

SECTION 3D. EMISSIONS - OTHER SOURCES

NO.		POLLUTANT	Max lbs/h	Avg lbs/hr	tons/y
S-O5	MAIN MILL	VOC	30.2	27.1	38.0
S-O2	A - SIDE SULFUR STOVE	SO2	2.1	1.3	3.9
S-O3	B - SIDE SULFUR STOVE	SO2	2.1	1.3	3.9

(1) Hourly production data cannot be determined, because of a batch process with significant hourly variability.
(2) Hourly averages on fugitive sources are calculated by dividing production by hours of beet campaign.

Section 5.4.3
Projected Emissions

SUMMARY OF CRITERIA POLLUTANT EMISSIONS - Future Emissions (All Boilers at PTE, Riley Coal Beet Campaign, Juice Run 75% Coal, 25%)
Nampa Facility - Annual Emissions

Table I

Beet run	**160 days**
Juice Run	**205 days**
Sep. Only	**11 days**

		PM			PM10			SO2			CO			NOx			VOC		
Source	ID	max lbs/hr	avg lbs/h	year tns/yr	max lbs/hr	avg lbs/h	year tns/yr	max lbs/hr	avg lbs/h	year tns/yr	max lbs/hr	avg lbs/h	year tns/yr	max lbs/hr	avg lbs/h	year tns/yr	max lbs/hr	avg lbs/h	year tns/yr
B&W Boiler No. 1	S-B1	2.7	2.7	12.0	2.7	2.7	12.0	0.1	0.1	0.3	10.5	10.5	46.0	35.3	35.3	154.5	0.7	0.7	3.0
B&W Boiler No. 2	S-B2	2.7	2.7	12.0	2.7	2.7	12.0	0.1	0.1	0.3	10.5	10.5	46.0	35.3	35.3	154.5	0.7	0.7	3.0
Riley Boiler	S-B3	14.3	13.3	58.3	12.4	11.7	51.3	425.0	365.4	1600.3	30.0	29.6	129.9	147.0	139.6	611.6	2.0	2.0	8.7
Union Boiler	S-B4	1.6	1.6	6.8	1.6	1.6	6.8	0.04	0.04	0.2	6.6	6.6	28.9	7.2	7.2	31.5	0.4	0.4	1.7
South Pulp Dryer	S-D1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Center Pulp Dryer	S-D2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
North Pulp Dryer	S-D3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pellet Cooler Baghouse	S-D9	0.80	0.80	3.50	0.80	0.80	3.50												
Lime Kiln A	S-K1	0.89	0.34	1.50	0.891	0.343	1.50	0.32	0.13	0.56	550.4	212.0	928.7	6.24	2.40	10.52	0.419	0.169	0.739
Lime Kiln B	S-K2	1.04	0.40	1.75	1.035	0.398	1.75	0.40	0.15	0.65	639.4	246.2	1078.2	7.25	2.79	12.22	0.524	0.195	0.855
Lime Kiln Material Handling	S-K3	2.04	0.79	3.45	2.04	0.79	3.45												
A & B Process Slakers	S-K4	1.40	1.39	6.10	1.40	1.39	6.10												
Drying Granulator	S-W1	1.10	1.14	5.00	1.10	1.14	5.00												
#1 Cooling Granulator	S-W2	0.30	0.30	1.30	0.30	0.30	1.30												
#2 Cooling Granulator	S-W3	0.30	0.30	1.30	0.30	0.30	1.30												
Sugar Handling(Process)	S-W4	0.30	0.27	1.20	0.30	0.27	1.20												
Sugar Handling(Specialties)	S-W6	0.10	0.14	0.60	0.10	0.14	0.60												
Sugar Handling(Pack Line)	S-W7	0.20	0.21	0.90	0.20	0.21	0.90												
Main Mill	S-O1																44.0	13.5	59.2
A Side Sulfur Stove	S-O2							2.1	1.6	7.1									
B Side Sulfur Stove	S-O3							2.1	1.6	7.1									
Coal Unloading (Railcar)@Dryer	FD9					0.00E+00	0.00E+00												
Pulp&Pellet Storage and Loadout	FD10					3.36E-03	1.47E-02												
C[illegible]nloading (Railcar)	FO4					7.56E-04	3.31E-03												
C[illegible]torage/Loading	FO5O6					0.41	1.79												
Beet Hauling	FO7					0.28	1.21												
Vehicle Traffic on Unpaved Roads	FO8					0.11	0.49												
Lime Rock Handling	FO9					0.15	0.68												
Coke Handling	FO10					0.05	0.20												
TOTAL	**TOTAL**	**29.7**	**26.4**	**115.6**	**27.9**	**25.8**	**113.0**	**430.2**	**369.1**	**1616.6**	**1247.4**	**515.5**	**2257.7**	**238.2**	**222.6**	**974.9**	**48.7**	**17.6**	**77.3**

30 days per year.

4.39

SECTION 3B. PRODUCTION DATA - BOILER HOUSE

NO.		MATERIAL	UNITS	Max Hr	Avg Hr	ANNUAL
S-B1	B & W BOILER NO. 1	Steam (Coal)-Beet	1000 lbs	0.0	0.0	0
		Coal (1)-Beet	Tons	0.0	0.0	0
		Steam (Natural Gas)-Beet	1000 lbs	105.0	105.0	919,800
		Natural Gas (1)-Beet	MMcf	0.0	0.0	0
		Steam (Coal)-Juice	1000 lbs	0.0	0.0	0
		Coal (1)-Juice	Tons	0.0	0.0	0
		Steam (Natural Gas)-Juice	1000 lbs	0.0	0.0	0
		Natural Gas (1)-Juice	MMcf	0.0	0.0	0
S-B2	B & W BOILER NO. 2	Steam (Coal)-Beet	1000 lbs	0.0	0.0	0
		Coal (1)-Beet	Tons	0.0	0.0	0
		Steam (Natural Gas)-Beet	1000 lbs	105.0	105.0	919,800
		Natural Gas (1)-Beet	MMcf	0.0	0.0	0
		Steam (Coal)-Juice	1000 lbs	0.0	0.0	0
		Coal (1)-Juice	Tons	0.0	0.0	0
		Steam (Natural Gas)-Juice	1000 lbs	0.0	0.0	0
		Natural Gas (1)-Juice	MMcf	0.0	0.0	0
S-B3	RILEY BOILER	Steam (Coal)-Beet	1000 lbs	250.0	250.0	960,000
		Coal (1)-Beet	Tons	18.0	18.0	0
		Steam (Natural Gas)-Beet	1000 lbs	0.0	0.0	0
		Natural Gas (1)-Beet	MMcf	0.0	0.0	0
		Steam (Coal)-Juice	1000 lbs	250.0	250.0	922,500
		Coal (1)-Juice	Tons	0.0	0.0	0
		Steam (Natural Gas)-Juice	1000 lbs	0.0	0.0	307,500
		Natural Gas (1)-Juice	MMcf	0.0	0.0	0
S-B4	UNION BOILER	Steam (Natural Gas)-Beet	1000 lbs	60.0	60.0	525,600
		Natural Gas (1)-Beet	MMcf	0.085	0.085	0
		Steam (Natural Gas)-Juice	1000 lbs	0.0	0	0
		Natural Gas (1)-Juice	MMcf	0.0	0	0

	Days	Hours	
Beet run	**160**	**3840**	**hrs.**
Juice Run	**205**	**4920**	**hrs.**
Sep. Only	**0**	**0**	**hrs.**
Totals	**365**	**8760**	**hrs.**

Total Steam(klbs)		4,555,200
Beet Steam (klbs)	73.00%	3,325,200
Juice Steam(klbs)	27.00%	1,230,000
Coal Steam (klbs)	41.33%	1,882,500
Gas Steam(klbs)	58.67%	2,672,700

SECTION 3C. EMISSION FACTORS - BOILER HOUSE

NO.		POLLUTANT	UNIT	EMISSION FACTOR (1) LB/UNIT	REFERENCE
S-B1	B & W BOILER NO.1 - STEAM(coal)	PM	1000 lbs	0.048	Boiler MACT Limit (0.04 lb/MMBtu)
		PM10	1000 lbs	0.048	Assume PM10 is equivalent to PM
		SO2	1000 lbs	1.80	AP-42, 9/98, Table 1.4-1, 0.8% sulfur
		CO	1000 lbs	0.147	Eng. Stack Test Oct 2009
		NOx	1000 lbs	0.550	Eng. Stack Test Oct 2009 & LNB's
		VOC	1000 lbs	0.0042	AP-42, 9/98, Table 1.4-1
	B & W BOILER NO.1 - STEAM (gas)	PM	1000 lbs	2.60E-02	IDAPA 58.01.01.677 0.015 gr/dscf grain loading standard
		PM10	1000 lbs	2.60E-02	Assume PM10 is equivalent to PM
		SO2	1000 lbs	7.20E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.00E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	3.36E-01	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	6.60E-03	AP-42, 9/98, Table 1.4-2
S-B2	B & W BOILER NO.2 - STEAM(coal)	PM	1000 lbs	0.048	Boiler MACT Limit (0.04 lb/MMBtu)
		PM10	1000 lbs	0.048	Boiler MACT Limit (0.04 lb/MMBtu)
		SO2	1000 lbs	1.80	AP-42, 9/98, Table 1.4-1, 0.8% sulfur
		CO	1000 lbs	0.147	Eng. Stack Test Oct 2009
		NOx	1000 lbs	0.550	Eng. Stack Test Oct 2009 & LNB's
		VOC	1000 lbs	0.0042	AP-42, 9/98, Table 1.4-1
	B & W BOILER NO.2 - STEAM (gas)	PM	1000 lbs	2.60E-02	IDAPA 58.01.01.677 0.015 gr/dscf grain loading standard
		PM10	1000 lbs	2.60E-02	Assume PM10 is equivalent to PM
		SO2	1000 lbs	7.20E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.00E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	3.36E-01	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	6.60E-03	AP-42, 9/98, Table 1.4-2
S-B3	RILEY BOILER - STEAM(coal)	PM	1000 lbs	0.057	Boiler MACT Limit (0.04 lb/MMBtu)
		PM10	1000 lbs	0.0496	Tier II BART Permit (12.4 lbs/h)
		SO2	1000 lbs	1.70	AP-42, 9/98, Table 1.4-1 & Assume 0.8% sulfur (bituminous)
		CO	1000 lbs	0.120	Eng. Stack Test Oct 2009
		NOx	1000 lbs	0.588	Tier II BART Permit (147 lbs/h)
		VOC	1000 lbs	0.0079	AP-42, 9/98, Table 1.4-1
	RILEY BOILER - STEAM (gas)	PM	1000 lbs	3.00E-02	IDAPA 58.01.01.677 0.015 gr/dscf grain loading standard
		PM10	1000 lbs	3.00E-02	Assume PM10 is equivalent to PM
		SO2	1000 lbs	8.60E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.10E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	3.78E-01	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	7.90E-03	AP-42, 9/98, Table 1.4-2
S-B4	UNION BOILER - STEAM (gas)	PM	1000 lbs	2.60E-02	IDAPA 58.01.01.677 0.015 gr/dscf grain loading standard
		PM10	1000 lbs	2.60E-02	Assume PM10 is equivalent to PM
		SO2	1000 lbs	7.20E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.10E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	1.20E-01	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	6.60E-03	AP-42, 7/98, Table 1.4-2

SECTION 3D. EMISSIONS - BOILER HOUSE

Based on campaign length (days) = 160

NO.		POLLUTANT	Max lb/hr	Avg. lbs./hr.	TONS/YR
S-B1	B & W BOILER NO. 1 (Beet)	PM	2.7	2.7	12.0
		PM10	2.7	2.7	12.0
		SO2	0.1	0.1	0.3
		CO	10.5	10.5	46.0
		NOx	35.3	35.3	154.5
		VOC	0.69	0.69	3.04
	B & W BOILER NO. 1 (Juice)	PM	0.0	0.0	0.0
		PM10	0.0	0.0	0.0
		SO2	0.0	0.0	0.0
		CO	0.0	0.0	0.0
		NOx	0.0	0.0	0.0
		VOC	0.0	0.0	0.0
S-B2	B & W BOILER NO. 2 (Beet)	PM	2.7	2.7	12.0
		PM10	2.7	2.7	12.0
		SO2	0.1	0.1	0.3
		CO	10.5	10.5	46.0
		NOx	35.3	35.3	154.5
		VOC	0.69	0.69	3.04
	B & W BOILER NO. 2 (Juice)	PM	0.0	0.0	0.0
		PM10	0.0	0.0	0.0
		SO2	0.0	0.0	0.0
		CO	0.0	0.0	0.0
		NOx	0.0	0.0	0.0
		VOC	0.0	0.0	0.0
S-B3	RILEY BOILER (Beet)	PM	14.3	14.3	27
		PM10	12.4	12.4	24
		SO2	425.0	425.0	816
		CO	30.0	30.0	58
		NOx	147.0	147.0	282
		VOC	2.0	2.0	4
	RILEY BOILER (Juice)	PM	14.3	14.3	31
		PM10	12.4	12.4	27
		SO2	425.0	425.0	784
		CO	30.0	30.0	72
		NOx	147.0	147.0	329
		VOC	2.0	2.0	5
S-B4	UNION BOILER (Beet)	PM	1.6	1.6	7
		PM10	1.6	1.6	7
		SO2	0.0	0.0	0
		CO	6.6	6.60	29
		NOx	7.2	7.2	32
		VOC	0.4	0.4	2
	UNION BOILER (Juice)	PM	0.0	0.0	0
		PM10	0.0	0.0	0
		SO2	0.0	0.0	0
		CO	0.0	0.0	0
		NOx	0.0	0.0	0
		VOC	0.0	0.0	0

11/12/2015

SECTION 3B. PRODUCTION DATA - LIME KILN AND CO2 PRODUCTION

NO.		MATERIAL	UNITS	Max Hrly	Avg Hrly	ANNUAL
S-K1	A LIME KILN	Lime Rock	Tons	9.9	8.7	33,408
		Coke	Tons	0.80	0.73	2,819
S-K2	B LIME KILN	Lime Rock	Tons	11.5	10.1	38,784
		Coke	Tons	1.00	0.85	3,262
S-K3	LIME KILN MATERIAL HANDLING	MATERIAL	Tons	35.1	30.9	118,600
S-K4	A&B PROCESS SLAKERS	CaO	Tons	11.9	10.5	40,320

SECTION 3C. EMISSION FACTORS - LIME KILN AND CO2 PRODUCTION

			EMISSION FACTOR (1)		
NO.		POLLUTANT	UNIT	LB/UNIT	REFERENCE
S-K1	A LIME KILN				
	- LIME ROCK	PM	Tons	0.0900	12/03 Source Test
		PM10	Tons	0.0900	12/03 Source Test
		CO	Tons	55.6	Eng. Stack Test Dec 2003
		NOx	Tons	0.63	AP-42, Boiler Table 1.2-1, Anthracite Coal
	- COKE	SO2	Tons	0.4	AP-42 Table 1.4-2 & 99% removal
		VOC	Tons	0.5240	Eng. est based on 2005 TF stack test
S-K2	B LIME KILN				
	- LIME ROCK	PM	Tons	0.0900	12/03 Source Test
		PM10	Tons	0.0900	12/03 Source Test
		CO	Tons	55.6	Eng. Stack Test Dec 2003
		NOx	Tons	0.63	AP-42, Boiler Table 1.2-1, Anthracite Coal
	-COKE	SO2	Tons	0.4	AP-42 Table 1.4-2 & 99% removal
		VOC	Tons	0.5240	Eng. est based on 2005 TF stack test
S-K3	LIME KILN MATERIAL HANDLING BAGHOUSE	PM	Tons	0.0582	Source test, Nov-05
	- MATERIAL HANDLED	PM10	Tons	0.0582	Source test, Nov-05
S-K4	PROCESS SLAKERS	PM	lbs/h	1.4	Tier I & Tier II Permit Limit
	-CaO	PM10	lbs/h	1.4	Tier I & Tier II Permit Limit

SECTION 3D. EMISSIONS - LIME KILN AND CO2 PRODUCTION

NO.		POLLUTANT	Max lbs./hr.	Avg. lbs./hr.	TONS/YR
S-K1	A LIME KILN	PM	0.89	0.78	1.50
		PM10	0.89	0.78	1.50
		SO2	0.32	0.29	0.6
		CO	550	484	929
		NOx	6.24	5.48	10.5
		VOC	0.42	0.38	0.74
S-K2	B LIME KILN	PM	1.04	0.91	1.75
		PM10	1.04	0.91	1.75
		SO2	0.40	0.34	0.7
		CO	639	561.6	1078.2
		NOx	7.25	6.36	12.22
		VOC	0.52	0.45	0.85
S-K3	LIME KILN MATERIAL	PM	2.04	1.80	3.45
	HANDLING BAGHOUSE	PM10	2.04	1.80	3.45
S-K4	PROCESS SLAKERS	PM	1.4	1.4	6.1
		PM10	1.4	1.4	6.1

(1) Hourly production data cannot be determined, because of a batch process with significant hourly variability.

SECTION 3B. PRODUCTION DATA - SUGAR WAREHOUSE AND SHIPPING

NO.		MATERIAL	UNITS	Max hrly	Hourly	ANNUAL
S-W1	DRYING GRANULATOR	Sugar	Tons	52.0	46.0	400,000
S-W2	NO. 1 COOLING GRANULATOR	Sugar	Tons	26.0	23.0	200,000
S-W3	NO. 2 COOLING GRANULATOR	Sugar	Tons	26.0	23.0	200,000
S-W4	SUGAR HANDLING (PROCESS #2)	NA	Hours	1.0	1.0	7440
S-W6	SUGAR HANDLING (SPECIALTIES)	NA	Hours	1.0	1.0	7440
S-W7	SUGAR HANDLING (PACK. LINE)	NA	Hours	1.0	1.0	7440

1) Assume max hourly is 15% above average hourly.

SECTION 3C. EMISSION FACTORS - SUGAR WAREHOUSE AND SHIPPING

NO.		POLLUTANT	EMISSION FACTOR (1) UNIT	LB/UNIT	REFERENCE
S-W1	DRYING GRANULATOR - SUGAR	PM	lbs/h	1.1	Tier I & Tier II Permit Limit
		PM10	lbs/h	1.1	Tier I & Tier II Permit Limit
S-W2	NO. 1 COOLING GRANULATOR - SUGAR	PM	lbs/h	0.3	Tier I & Tier II Permit Limit
		PM10	lbs/h	0.3	Tier I & Tier II Permit Limit
S-W3	NO. 2 COOLING GRANULATOR - SUGAR	PM	lbs/h	0.3	Tier I & Tier II Permit Limit
		PM10	lbs/h	0.3	Tier I & Tier II Permit Limit
S-W4	SUGAR HANDLING (PROCESS #2)	PM	lbs/h	0.3	Tier I & Tier II Permit Limit
		PM10	lbs/h	0.3	Tier I & Tier II Permit Limit
S-W6	SUGAR HANDLING (SPECIALTIES)	PM	lbs/h	0.1	Tier I & Tier II Permit Limit
		PM10	lbs/h	0.1	Tier I & Tier II Permit Limit
S-W7	SUGAR HANDLING (PACK. LINE)	PM	lbs/h	0.2	Tier I & Tier II Permit Limit
		PM10	lbs/h	0.2	Tier I & Tier II Permit Limit

SECTION 3D. EMISSIONS - SUGAR WAREHOUSE AND SHIPPING

NO.		POLLUTANT	Max lbs./hr.	Avg. lbs./hr.	TONS/YR
S-W1	DRYING GRANULATOR - SUGAR (tons)	PM	1.10	1.10	5.00
		PM10	1.10	1.10	5.00
S-W2	NO. 1 COOLING GRANULATOR - SUGAR	PM	0.30	0.30	1.30
		PM10	0.30	0.30	1.30
S-W3	NO. 2 COOLING GRANULATOR - SUGAR	PM	0.30	0.30	1.30
		PM10	0.30	0.30	1.30
S-W4	SUGAR HANDLING (PROCESS #2)	PM	0.30	0.30	1.20
		PM10	0.30	0.30	1.20
S-W6	SUGAR HANDLING (SPECIALTIES)	PM	0.10	0.10	0.60
		PM10	0.10	0.10	0.60
S-W7	SUGAR HANDLING (PACK. LINE)	PM	0.20	0.20	0.90
		PM10	0.20	0.20	0.90

SECTION 3B. PRODUCTION DATA - OTHER SOURCES

NO.		MATERIAL	UNITS	Max Hrly	Avg Hrly	ANNUAL
S-O5	MAIN MILL	Thin Juice	1000 gal	159.0	142	427,728
S-O2	A - SIDE SULFUR STOVE	Sulfur	Tons	0.021	0.016	140
S-O3	B - SIDE SULFUR STOVE	Sulfur	Tons	0.021	0.016	140

(2) Estimating thin juice flow from diffuser operation in 2002-03 campaign of 273 gal./ton beets.

SECTION 3C. EMISSION FACTORS - OTHER SOURCES

NO.		POLLUTANT	UNIT	EMISSION FACTOR (1) LB/UNIT	REFERENCE
S-O5	MAIN MILL	VOC	1000 gal	0.277	2005 Beet Campaign - Non validated test method
S-O2	A - SIDE SULFUR STOVE	SO2	lb/ton	101.64	July 1992 Eng Stack Test @ Nampa , 20% safety factor
S-O3	B - SIDE SULFUR STOVE	SO2	lb/ton	101.64	July 1992 Eng Stack Test @ Nampa , 20% safety factor

(1) See Appendix G for emission factor documentation.

SECTION 3D. EMISSIONS - OTHER SOURCES

NO.		POLLUTANT	Max lbs/h	Avg lbs/hr	tons/y
S-O5	MAIN MILL	VOC	44.0	39.3	59.2
S-O2	A - SIDE SULFUR STOVE	SO2	2.1	1.6	7.1
S-O3	B - SIDE SULFUR STOVE	SO2	2.1	1.6	7.1

2006-2007 Average vs Future

GHG Baseline Emissions Summary
Nampa Facility

Source	CO2 (tons/y)	CH4 (tons/y)	N2O (tons/y)	CO2e (tons/y)
Total - Boilers	334920	37	5.4	337435
Total - Pulp Dryers	67904	5.2	0.8	68262
Total - Lime Kilns	13015	1	0.2	13110
Total	415839	43	6.3	418807

Future Emissions Summary
Nampa Facility

Source	CO2 (tons/y)	CH4 (tons/y)	N2O (tons/y)	CO2e (tons/y)
Total - Boilers	446421	32.0	4.5	446421
Total - Pulp Dryers	0	0	0.0	0
Total - Lime Kilns	16951	1.9	0.3	16951
Total	463372	34	4.8	463372

GHG Net Emissions Summary
Nampa Facility

Source	CO2 (tons/y)	CH4 (tons/y)	N2O (tons/y)	CO2e (tons/y)
Total - Boilers	111501	-5	-0.8	108986
Total - Pulp Dryers	-67904	-5.2	-0.8	-68262
Total - Lime Kilns	3935	1	0.1	3840
Total	47533	-9	-1.5	44565

GHG Emissions Estimates
Future Projected
The Amalgamated Sugar Co. LLC
Nampa Facility

Source Name	Source ID	Annual	Units	Parameter	Factor	Emissions Units	Reference	Annual Emissions (tons/y)
No. 1 & No. 2 B&W Boilers	S-B1 & S-B2	0	klbs steam - coal	CO_2	267	lbs/klb steam	40CFR98 Subpart C Table C-1	0
		0	klbs steam - coal	CH_4	0.03	lbs/klb steam	40CFR98 Subpart C Table C-2	0
		0	klbs steam - coal	N_2O	0.0044	lbs/klb steam	40CFR98 Subpart C Table C-2	0.0
		1839600	klbs steam - gas	CO_2	146	lbs/klb steam	40CFR98 Subpart C Table C-1	134291
		1839600	klbs steam - gas	CH_4	0.0028	lbs/klb steam	40CFR98 Subpart C Table C-2	3
		1839600	klbs steam - gas	N_2O	0.00028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.3
Riley Boiler	S-B3	1882500	klbs steam - coal	CO_2	267	lbs/klb steam	40CFR98 Subpart C Table C-1	251314
		1882500	klbs steam - coal	CH_4	0.03	lbs/klb steam	40CFR98 Subpart C Table C-2	28
		1882500	klbs steam - coal	N_2O	0.0044	lbs/klb steam	40CFR98 Subpart C Table C-2	4
		307500	klbs steam - gas	CO_2	146	lbs/klb steam	40CFR98 Subpart C Table C-1	22448
		307500	klbs steam - gas	CH_4	0.0028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.43
		307500	klbs steam - gas	N_2O	0.00028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.04
Union Boiler	S-B4	525600	klbs steam - gas	CO_2	146	lbs/klb steam	40CFR98 Subpart C Table C-1	38369
		525600	klbs steam - gas	CH_4	0.0028	lbs/klb steam	40CFR98 Subpart C Table C-2	1
		525600	klbs steam - gas	N_2O	0.00028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.1

	CO_2(tons/y)	CH_4(ton/y)	N_2O(tons/y)
Total - Boilers	446421	32.0	4.5
Global Warming Factors	1	25	298
CO2e	446421	799	1346
Total CO2e	448566		

Source Name	Source ID	Annual	Units	Parameter	Factor	Emissions Units	Reference	Annual Emissions (tons/y)
South Pulp Dryer	S-D1	0	tons - coal	CO_2	4606	lbs/ton coal	40CFR98 Subpart C Table C-1	0
		0	tons - coal	CH_4	0.518	lbs/ton coal	40CFR98 Subpart C Table C-2	0
		0	tons - coal	N_2O	0.076	lbs/ton coal	40CFR98 Subpart C Table C-2	0.0
Center Pulp Dryer	S-D2	0	tons - coal	CO_2	4606	lbs/ton coal	40CFR98 Subpart C Table C-1	0
		0	tons - coal	CH_4	0.518	lbs/ton coal	40CFR98 Subpart C Table C-2	0
		0	tons - coal	N_2O	0.076	lbs/ton coal	40CFR98 Subpart C Table C-2	0
North Pulp Dryer	S-D3	0	tons - coal	CO_2	4606	lbs/ton coal	40CFR98 Subpart C Table C-1	0
		0	tons - coal	CH_4	0.518	lbs/ton coal	40CFR98 Subpart C Table C-2	0
		0	tons - coal	N_2O	0.076	lbs/ton coal	40CFR98 Subpart C Table C-2	0.0

	CO_2(tons/y)	CH_4(ton/y)	N_2O(tons/y)
Total - Pulp Dryers	0	0	0.0
Global Warming Factors	1	25	298
CO2e	0	0	0
Total CO2e	0		

Source Name	Source ID	Annual	Units	Parameter	Factor	Emissions Units	Reference	Annual Emissions (tons/y)
A Lime Kiln	S-K1	2819	tons - coke	CO_2	5575	lbs/ton coke	40CFR98 Subpart C Table C-1	7858
		2819	tons - coke	CH_4	0.624	lbs/ton coke	40CFR98 Subpart C Table C-2	0.9
		2819	tons - coke	N_2O	0.091	lbs/ton coke	40CFR98 Subpart C Table C-2	0.13
B Lime Kiln	S-K2	3262	tons - coke	CO_2	5575	lbs/ton coke	40CFR98 Subpart C Table C-1	9093
		3262	tons - coke	CH_4	0.624	lbs/ton coke	40CFR98 Subpart C Table C-2	1.0
		3262	tons - coke	N_2O	0.091	lbs/ton coke	40CFR98 Subpart C Table C-2	0.1

	CO_2(tons/y)	CH_4(ton/y)	N_2O(tons/y)
Total - Lime Kilns	16951	1.9	0.3
Global Warming Factors	1	25	298
CO2e	16951	47	82
Total CO2e	17081		

GHG Emissions Estimates
Baseline Period (Average 2006-2007)
The Amalgamated Sugar Co. LLC
Nampa Facility

Source Name	Source ID	Annual	Units	Emissions Parameter	Factor	Units	Reference	Annual Emissions (tons/y)
No. 1 & No. 2 B&W Boilers	S-B1 & S-B2	802287	klbs steam - coal	CO_2	267	lbs/klb steam	40CFR98 Subpart C Table C-1	107105
		802287	klbs steam - coal	CH_4	0.03	lbs/klb steam	40CFR98 Subpart C Table C-2	12
		802287	klbs steam - coal	N_2O	0.0044	lbs/klb steam	40CFR98 Subpart C Table C-2	1.8
		21137	klbs steam - gas	CO_2	146	lbs/klb steam	40CFR98 Subpart C Table C-1	1543
		21137	klbs steam - gas	CH_4	0.0028	lbs/klb steam	40CFR98 Subpart C Table C-2	0
		21137	klbs steam - gas	N_2O	0.00028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.0
Riley Boiler	S-B3	1627432	klbs steam - coal	CO_2	267	lbs/klb steam	40CFR98 Subpart C Table C-1	217262
		1627432	klbs steam - coal	CH_4	0.03	lbs/klb steam	40CFR98 Subpart C Table C-2	24
		1627432	klbs steam - coal	N_2O	0.0044	lbs/klb steam	40CFR98 Subpart C Table C-2	4
		27374	klbs steam - gas	CO_2	146	lbs/klb steam	40CFR98 Subpart C Table C-1	1998
		27374	klbs steam - gas	CH_4	0.0028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.04
		27374	klbs steam - gas	N_2O	0.00028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.00
Union Boiler	S-B4	96038	klbs steam - gas	CO_2	146	lbs/klb steam	40CFR98 Subpart C Table C-1	7011
		96038	klbs steam - gas	CH_4	0.0028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.1
		96038	klbs steam - gas	N_2O	0.00028	lbs/klb steam	40CFR98 Subpart C Table C-2	0.01

	CO_2(tons/y)	CH_4(ton/y)	N_2O(tons/y)
Total - Boilers	334920	36.6	5
Global Warming Factors	1	25	298
CO2e	334920	916	1599
Total CO2e	337435		

Source Name	Source ID	Annual	Units	Emissions Parameter	Factor	Units	Reference	Annual Emissions (tons/y)
South Pulp Dryer	S-D1	103912	tons input	CO_2	548	lbs/ton input	40CFR98 Subpart C Table C-1	28472
		9816	tons - coal	CH_4	0.414	lbs/ton coal	40CFR98 Subpart C Table C-2	2
		9816	tons - coal	N_2O	0.0604	lbs/ton coal	40CFR98 Subpart C Table C-2	0.3
Center Pulp Dryer	S-D2	103912	tons input	CO_2	548	lbs/ton input	40CFR98 Subpart C Table C-1	28472
		9816	tons - coal	CH_4	0.414	lbs/ton coal	40CFR98 Subpart C Table C-2	2.0
		9816	tons - coal	N_2O	0.0604	lbs/ton coal	40CFR98 Subpart C Table C-2	0.3
North Pulp Dryer	S-D3	40000	tons input	CO_2	548	lbs/ton input	40CFR98 Subpart C Table C-1	10960
		5618	tons - coal	CH_4	0.414	lbs/ton coal	40CFR98 Subpart C Table C-2	1.2
		5618	tons - coal	N_2O	0.0604	lbs/ton coal	40CFR98 Subpart C Table C-2	0.2

	CO_2(tons/y)	CH_4(ton/y)	N_2O(tons/y)
Total - Pulp Dryers	67904	5.2	0.8
Global Warming Factors	1	25	298
CO2e	67904	131	227
Total CO2e	68262		

Source Name	Source ID	Annual	Units	Emissions Parameter	Factor	Units	Reference	Annual Emissions (tons/y)
A Lime Kiln	S-K1	2055	tons - coke	CO_2	5580	lbs/ton coke	40CFR98 Subpart C Table C-1	5733
		2055	tons - coke	CH_4	0.595	lbs/ton coke	40CFR98 Subpart C Table C-2	0.6
		2055	tons - coke	N_2O	0.0868	lbs/ton coke	40CFR98 Subpart C Table C-2	0.09
B Lime Kiln	S-K2	2610	tons - coke	CO_2	5580	lbs/ton coke	40CFR98 Subpart C Table C-1	7282
		2610	tons - coke	CH_4	0.595	lbs/ton coke	40CFR98 Subpart C Table C-2	0.8
		2610	tons - coke	N_2O	0.0868	lbs/ton coke	40CFR98 Subpart C Table C-2	0.1

	CO_2(tons/y)	CH_4(ton/y)	N_2O(tons/y)
Total - Lime Kilns	13015	1.4	0.20
Global Warming Factors	1	25	298
CO2e	13015	35	60
Total CO2e	13110		

Projected HAPs
Emissions Summary
Nampa Facility

HAP Pollutants	PTE (t/y)
Acetaldehyde	2.50
Acrolein	0.07
Formaldehyde	0.16
Methanol	46.63
Arsenic	0.03
Benzene	0.07
Beryllium	0.00
Cadmium	0.05
Chromium	0.02
Cyanide	0.19
Hydrochloric Acid	1.01
Hydrogen Fluoride	3.80
Lead	0.03
Manganese	0.04
Mercury	0.00
Nickel	0.02
Selenium	0.10
Toluene	0.02
Xylenes	0.00
PAH and other HAPs	0.20
Total	54.96

HAP Projected Emissions Nampa Facility

Individual Emissions - Projected

Hazardous Air Pollutant (HAP)	B & W Boiler Coal (tons / year)	B & W Boiler Nat. Gas (tons / year)	Riley Boiler Coal (tons / year)	Riley Boiler Nat. Gas (tons / year)	Union Nat. Gas (tons / year)	Coal Fired Pulp Dryers (tons / year)	Kilns (tons / year)	Main Mill (tons / year)	Constituent Totals (tons / year)
Acetaldehyde	0.00	0.00	0.03	0.00	0.00	0.00	0.00	2.47	2.50
Acrolein	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.06	0.07
Formaldehyde	0.00	0.0863	0.0129	1.59E-02	2.46E-02	0.00	0.00	0.02	0.16
Methanol								46.63	46.63
Arsenic	0.00	0.00	0.02	0.00	6.57E-05	0.00	8.5E-03		0.03
Benzene	0.00	0.00	0.07	0.00	6.90E-04	0.00	0.00		0.07
Beryllium	0.00	0.00	0.00	0.00	3.94E-06	0.00	4.4E-04		0.00
Cadmium	0.00	0.00	0.00	0.00	3.61E-04	0.00	4.3E-02		0.05
Chromium	0.00	0.00	0.01	0.00	4.60E-04	0.00	5.4E-03		0.02
Cyanide	0.00		0.13			0.00	5.2E-02		0.19
Hydrochloric Acid	0.00		1.01			0.00	0.00		1.01
Hydrogen Fluoride	0.00		3.80			0.00	0.00		3.80
Lead	0.00	0.00	0.02	0.00	1.64E-04	0.00	8.7E-03		0.03
Manganese	0.00	0.00	0.03	0.00	1.25E-04	0.00	1.0E-02		0.04
Mercury	0.00	0.00	0.00	0.00	8.54E-05	0.00	1.0E-03		0.0035
Nickel	0.00	0.00	0.02	0.00	6.90E-04	0.00	5.8E-03		0.02
Selenium	0.00	0.00	0.07	0.00	7.88E-06	0.00	2.7E-02		0.10
Toluene	0.00	0.00	0.01	0.00	1.12E-03	0.00	0.00		0.02
Xylenes	0.00		0.00			0.00	0.00		0.00
PAH and other HAPs	0.00	0.00	0.20	0.00	2.90E-05	0.00	0.00		0.20
	0.00	0.10	5.46	0.02	0.03	0.00	0.16	49.18	
								Grand Total	**54.96**

1. PAH and Other HAP emission factors are listed in the Fuel E_Factors sheet and include the following

2,4-Dinitrotoluene, 2-Chloroacetophenone, Acetophenone, Antimony Compounds, Benzyl chloride, Bis(2-ethylhexyl)phthalate (DEHP), Bromoform, Carbon disulfide, Chlorobenzene, Chloroform, Cobalt Compounds, Cumene, Dimethyl sulfate, Ethyl benzene, Ethyl chloride (Chloroethane), Ethylene dibromide (Dibromoethane), Ethylene dichloride (1,2-Dichloroethane), Hexane, Isophorone, Methyl bromide (Bromomethane), Methyl chloride (Chloromethane), Methyl chloroform (1,1,1-Trichloroethane), Methyl hydrazine, Methyl Methacylate, Methyl tert butyl ether, Methylene chloride (Dichloromethane), Phenol, Propionaldehyde, Styrene, Tetrachloroethylene

HAP's Emissions Inventory
Production Rate Assumptions
Nampa Facility

No.		Material	Units	Annual
S-B1	B & W Boilers	Steam (from Natural Gas) Beet Run	1000 lbs	1,839,600
		(Natural Gas) Beet Run	MM cf	2,300.0
		Steam (from Coal) Beet Run	1000 lbs	0
		Coal Beet Run	Tons	0
		Steam (from Natural Gas) Juice Run	1000 lbs	0
		(Natural Gas) Juice Run	MM cf	0
		Steam (from Coal) Juice Run	1000 lbs	0
		Coal Juice Run	Tons	0
S-B2	Riley Boiler	Steam (from Natural Gas) Beet Run	1000 lbs	
		(Natural Gas) Beet Run	MM cf	
		Steam (from Coal) Beet Run	1000 lbs	1,882,500
		Coal Beet Run	Tons	107,852
		Steam (from Natural Gas) Juice Run	1000 lbs	307,500
		(Natural Gas) Juice Run	MM cf	423
		Steam (from Coal) Juice Run	1000 lbs	
		Coal Juice Run	Tons	
S-B3	Union Boiler	Steam (from Natural Gas) Beet Run	1000 lbs	525,600
		(Natural Gas) Beet Run	MM cf	657.0
		Steam (from Natural Gas) Juice Run	1000 lbs	0
		(Natural Gas) Juice Run	MM cf	0
S-D1	Coal Fired Pulp Dryers	Total Input	Tons	0
		Coal	Tons	0
		Natural Gas	MM cf	0.00
S-K1	A lime Kiln (Coke Kiln)	Coke	Tons	2,819
		Lime Rock	Tons	33,408
	B lime Kiln (Coke Kiln)	Coke	Tons	3,262
S-K2		Lime Rock	Tons	38,784
S-D5	Main Mill	Thin Juice	1000 Gallons (k-gals)	546,000

Emissio. .actors
Categorized According to Fuel

Pollutants from Coal Combustion	EMISSION FACTOR UNIT	LB/UNIT	REFERENCE
Acetaldehyde	ton coal	5.70E-04	See Note (a.)
Acrolein	ton coal	2.90E-04	See Note (a.)
Arsenic	ton coal	4.10E-04	See Note (b.)
Benzene	ton coal	1.30E-03	See Note (a.)
Beryllium	ton coal	2.10E-05	See Note (b.)
Cadmium	ton coal	5.10E-05	See Note (b.)
Chromium	ton coal	2.60E-04	See Note (b.)
Cyanide	ton coal	2.50E-03	See Note (a.)
Formaldehyde	ton coal	2.40E-04	See Note (a.)
Hydrochloric Acid from P & M coal through Fabric Filter	ton coal	1.87E-02	See Note (c.)
Hydrogen Fluoride from P & M coal through Fabric Filter	ton coal	7.04E-02	See Note (c.)
Hydrochloric Acid from P & M coal through Scrubber	ton coal	5.29E-03	See Note (c.)
Hydrogen Fluoride from P & M coal through Scrubber	ton coal	6.34E-03	See Note (c.)
Lead	ton coal	4.20E-04	See Note (b.)
Manganese	ton coal	4.90E-04	See Note (b.)
Mercury	ton coal	3.73E-05	See Note (e.)
Nickel	ton coal	2.80E-04	See Note (b.)
PAH (see below)			
Selenium	ton coal	1.30E-03	See Note (b.)
Toluene	ton coal	2.40E-04	See Note (a.)
Xylenes	ton coal	3.70E-05	See Note (a.)

Notes

a. AP-42, 9/98, Table 1.1-14, Emission Factors for Various Organic Compounds from Controlled Coal Combustion

b. AP-42, 9/98, Table 1.1-18, Emission Factors from Trace Metals From Controlled Coal Combustion

c. EF derived from material balance calculations based on USGS Data and/or TASCO's mine specific data and EPA Emissions Modification Factors in EPA's 1998 Report to Congress

d. AP-42, 9/98, Table 1.1-13, Emission Factors from Trace Metals From Controlled Coal Combustion.

e. Based on 9/2006 engineering stack test.

Emission Factors
Categorized According to Fuel

Other HAPs from Coal Combustion	UNIT	LB/UNIT	REFERENCE
2,4-Dinitrotoluene	ton coal	2.80E-07	See Note (a.)
2-Chloroacetophenone	ton coal	7.00E-06	See Note (a.)
Acetophenone	ton coal	1.50E-05	See Note (a.)
Antimony Compounds	ton coal	1.80E-05	See Note (b.)
Benzyl chloride	ton coal	7.00E-04	See Note (a.)
Bis(2-ethylhexyl)phthalate (DEHP)	ton coal	7.30E-05	See Note (a.)
Bromoform	ton coal	3.90E-05	See Note (a.)
Carbon disulfide	ton coal	1.30E-04	See Note (a.)
Chlorobenzene	ton coal	2.20E-05	See Note (a.)
Chloroform	ton coal	5.90E-05	See Note (a.)
Cobalt Compounds	ton coal	1.00E-04	See Note (b.)
Cumene	ton coal	5.30E-06	See Note (a.)
Dimethyl sulfate	ton coal	4.80E-05	See Note (a.)
Ethyl benzene	ton coal	9.40E-05	See Note (a.)
Ethyl chloride (Chloroethane)	ton coal	4.20E-05	See Note (a.)
Ethylene dibromide (Dibromoethane)	ton coal	1.20E-06	See Note (a.)
Ethylene dichloride (1,2-Dichloroethane)	ton coal	4.00E-05	See Note (a.)
Hexane	ton coal	6.70E-05	See Note (a.)
Isophorone	ton coal	5.80E-04	See Note (a.)
Methyl bromide (Bromomethane)	ton coal	1.60E-04	See Note (a.)
Methyl chloride (Chloromethane)	ton coal	5.30E-04	See Note (a.)
Methyl chloroform (1,1,1-Trichloroethane)	ton coal	2.00E-05	See Note (a.)
Methyl hydrazine	ton coal	1.70E-04	See Note (a.)
Methyl Methacylate	ton coal	2.00E-05	See Note (a.)
Methyl tert butyl ether	ton coal	3.50E-05	See Note (a.)
Methylene chloride (Dichloromethane)	ton coal	2.90E-04	See Note (a.)
Phenol	ton coal	1.60E-05	See Note (a.)
Propionaldehyde	ton coal	3.80E-04	See Note (a.)
Styrene	ton coal	2.50E-05	See Note (a.)
Tetrachloroethylene (Perchloroethylene)	ton coal	4.30E-05	See Note (a.)
Vinyl Acetate	ton coal	7.60E-06	See Note (a.)

Emissio.. .actors
Categorized According to Fuel

Polynuclear Aromatic Hydorcarbons From Coal Combustion	UNIT	LB/UNIT	REFERENCE
Biphenyl	ton coal	1.70E-06	See Note (d.)
Acenaphthene	ton coal	5.10E-07	See Note (d.)
Acenaphthylene	ton coal	2.50E-07	See Note (d.)
Anthracene	ton coal	2.10E-07	See Note (d.)
Benzo(a)anthracene	ton coal	8.00E-08	See Note (d.)
Beno(a)pyrene	ton coal	3.80E-08	See Note (d.)
Benzo(b,j,k)fluoranthene	ton coal	1.10E-07	See Note (d.)
Benzo(g,h,I)perylene	ton coal	2.70E-08	See Note (d.)
Chrysene	ton coal	1.00E-07	See Note (d.)
Fluoranthene	ton coal	7.10E-07	See Note (d.)
Fluorene	ton coal	9.10E-07	See Note (d.)
Indeno(1,2,3-cd)pyrene	ton coal	6.10E-08	See Note (d.)
Naphthalene	ton coal	1.30E-05	See Note (d.)
Phenanthrene	ton coal	2.70E-06	See Note (d.)
Pyrene	ton coal	3.30E-07	See Note (d.)
5-Methyl chrysene	ton coal	2.20E-08	See Note (d.)
Total of all HAPs from Coal Combustion (Except HCl and HF)	lbs / ton	1.13E-01	
To convert Emission Factor from lb/ton coal to lb / 1000 lbs steam,			
For the B&W boiler, multiply the above EF by		6.06E-02	ton coal / 1000 lb steam
For the Riley boiler, multiply the above EF by		7.23E-02	ton coal / 1000 lb steam

Emission Factors
Categorized According to Fuel

Pollutants from Natural Gas Combustion	UNIT	LB/UNIT	REFERENCE
Arsenic	MMCF	2.00E-04	See Note (f.)
Benzene	MMCF	2.10E-03	See Note (g.)
Beryllium	MMCF	1.20E-05	See Note (f.)
Cadmium	MMCF	1.10E-03	See Note (f.)
Chromium	MMCF	1.40E-03	See Note (f.)
Cobalt	MMCF	8.40E-05	See Note (f.)
Dichlorobenzene	MMCF	1.20E-03	See Note (g.)
Formaldehyde	MMCF	7.50E-02	See Note (g.)
Hexane	MMCF	1.80E+00	See Note (g.)
Lead	MMCF	5.00E-04	See Note (h.)
Manganese	MMCF	3.80E-04	See Note (f.)
Mercury	MMCF	2.60E-04	See Note (f.)
Naphthalene	MMCF	6.10E-04	See Note (g.)
Nickel	MMCF	2.10E-03	See Note (f.)
PAH (see below)			
Selenium	MMCF	2.40E-05	See Note (f.)
Toluene	MMCF	3.40E-03	See Note (g.)

Polynuclear Aromatic Hydorcarbons From Natural Gas Combustion	UNIT	LB/UNIT	REFERENCE
2-Methylnaphthalene	MMCF	2.40E-05	See Note (g.)
3-Methylchloranthrene	MMCF	1.80E-06	See Note (g.)
7, 12-Dimethylbenz(a)anthracene	MMCF	1.60E-05	See Note (g.)
Acenaphthene	MMCF	1.80E-06	See Note (g.)
Acenaphthylene	MMCF	1.80E-06	See Note (g.)
Anthracene	MMCF	2.40E-06	See Note (g.)
Benz(a)_anthracene	MMCF	1.80E-06	See Note (g.)
Benzo(a)pyrene	MMCF	1.20E-06	See Note (g.)
Benzo(b)fluoranthene	MMCF	1.80E-06	See Note (g.)
Benzo(g,h,I)perylene	MMCF	1.20E-06	See Note (g.)
Benzo(k)fluoranthene	MMCF	1.80E-06	See Note (g.)
Chrysene	MMCF	1.80E-06	See Note (g.)
Dibenzo(a,h)anthracene	MMCF	1.20E-06	See Note (g.)
Fluoranthene	MMCF	3.00E-06	See Note (g.)
Fluorene	MMCF	2.80E-06	See Note (g.)
Indeno(1,2,3-cd)pyrene	MMCF	1.80E-06	See Note (g.)
Phenanathrene	MMCF	1.70E-05	See Note (g.)
Pyrene	MMCF	5.00E-06	See Note (g.)
Total of all HAPs from Natural Gas Combustion	MMCF	1.89E+00	
To convert Emission Factor from lb/MMCF Nat Gas to lb / 1000 lbs steam,			
For the B&W boiler, multiply the above EF by		1.20E-03	MM CF / 1000 lb steam
For the Riley boiler, multiply the above EF by		1.43E-03	MM CF / 1000 lb steam
For the Union boiler, multiply the above EF by		1.25E-03	MM CF / 1000 lb steam

Notes

f. AP-42, 7/98, Table 1.4-4, Emission Factors for Metals from Natural Gas Combustion
g. AP-42, 7/98, Table 1.4-3, Emission Factors for Speciated Organic Compounds from Natural Gas Combustion
h. AP-42, 7/98, Table 1.4-2, Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion

Emission Factors
Categorized According to Fuel

Pollutants from Coke Combustion	EMISSION FACTOR		
	UNIT	LB/UNIT	REFERENCE
Acetaldehyde	ton coal	0.00E+00	See Note (m.)
Acrolein	ton coal	0.00E+00	See Note (m.)
Arsenic	ton coal	4.10E-04	See Note (b.)
Benzene	ton coal	0.00E+00	See Note (m.)
Beryllium	ton coal	2.10E-05	See Note (b.)
Cadmium	ton coal	5.10E-05	See Note (b.)
Chromium	ton coal	2.60E-04	See Note (b.)
Cyanide	ton coal	2.50E-03	See Note (b.)
Formaldehyde	ton coal	0.00E+00	See Note (m.)
Hydrochloric Acid	ton coal	0.00E+00	See Note (m.)
Hydrogen Fluoride	ton coal	0.00E+00	See Note (m.)
Lead	ton coal	4.20E-04	See Note (b.)
Manganese	ton coal	4.90E-04	See Note (b.)
Mercury	ton coal	0.00E+00	See Note (m.)
Nickel	ton coal	2.80E-04	See Note (b.)
PAH	ton coal	0.00E+00	See Note (m.)
Selenium	ton coal	1.30E-03	See Note (b.)
Toluene	ton coal	0.00E+00	See Note (m.)
Xylenes	ton coal	0.00E+00	See Note (m.)
Other HAPS	ton coal	0.00E+00	See Note (m.)
All Haps from Coke Fired Kiln Operations	ton coal	5.73E-03	

Notes

m. No VOC or Hg emissions are identified in AP-42 for coke combustion. VOC and Hg are assumed to volitize in the formation of Coke.

b. Metal HAPs are estimated based on AP 42 for bituminous coal.

Pollutants from Lime Rock	EMISSION FACTOR UNIT	LB/UNIT	REFERENCE
Cadmium	ton lime rock	1.20E-03	See Note (o.)
Mercury	ton lime rock	2.90E-05	See Note (p.)

Notes

o. EF based on material balance calculations using analytical results of Ash Grove Cement Company Sweet Rock samples collected on 10/18/06

p. EF based on material balance calculations using analytical results of Ash Grove Cement Company Sweet Rock samples collected on 10/18/07 and Precipitated Calcium Carbonate analysis performed by Stukenholtz Laboratory, INC

Total Dryer Input

POLLUTANT	UNIT	LB/UNIT	REFERENCE
Acetaldehyde	Tons	1.92E-02	See Note (j.)
Acrolein	Tons	9.30E-03	See Note (j.)
Formaldehyde	Tons	9.42E-03	See Note (j.)
Mercury	Tons	7.00E-05	See Note (c.)
Total of all HAPs from Total Steam Dryer Input	MMCF	3.80E-02	

Main Mill Emissions

POLLUTANT	UNIT	LB/UNIT	REFERENCE
Acetaldehyde	1000 gallons	9.06E-03	See Note (k.)
Acrolein	1000 gallons	2.10E-04	See Note (j.)
Formaldehyde	1000 gallons	8.28E-05	See Note (k.)
Methanol 1st Carbonation Tank Stack	1000 gallons	6.89E-02	Engineering Estimate
Methanol 2nd Carbonation Tank Stack	1000 gallons	2.87E-02	Engineering Estimate
Methanol Evaporators	1000 gallons	7.33E-02	Engineering Estimate
Main Mill Methanol	1000 gallons	1.71E-01	Engineering Estimate
Total of all HAPs from Main Mill Thin Juice Flow	MMCF	3.51E-01	

Notes

j. Nampa Source Test "Particulate, Aldehyde, and Semi-Volatile Organic Compound (SVOC) Testing Report for the Pulp Dryer Stacks, 1st and 2nd Carbonation Tank Vents, and the Evaporator Heater Vents" submitted to Idaho Department of Environmental Quality May 1

k. Twin Falls and Nampa Source Tests (2003)

EMISSION FACTOR SUMMARY - BOILER HOUSE

Nampa Facility

11/5/2015

NO.		POLLUTANT	UNIT	EMISSION FACTOR [1] LB/UNIT	REFERENCE
S-B1	B & W BOILER NO.1	PM	1000 lbs	0.0480	Boiler MACT Limit (0.04 lb/MMBtu)
	- STEAM(coal)	PM10	1000 lbs	0.0480	Assume PM10 is equivalent to PM
		SO2	1000 lbs	1.800	AP-42, 9/98, Table 1.4-1, 0.8% sulfur
		CO	1000 lbs	0.147	Eng. StackTest Oct. 2009
		NOx	1000 lbs	1.10	Eng. Stack Test - Oct. 2009
		NOx	1000 lbs	0.55	2009 Eng. Stack Test & 50% removal (low Nox burners)
		VOC	1000 lbs	0.0042	AP-42, 9/98, Table 1.4-1
	B & W BOILER NO.1	PM	1000 lbs	2.60E-02	IDAPA 58.01.01.677 0.015 gr/dscf grain loading standard
	- STEAM (gas)	PM10	1000 lbs	2.60E-02	Assume PM10 is equivalent to PM
		SO2	1000 lbs	7.20E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.00E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	3.36E-01	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	6.60E-03	AP-42, 9/98, Table 1.4-2
S-B2	B & W BOILER NO.2	PM	1000 lbs	0.0480	Boiler MACT Limit (0.04 lb/MMBtu)
	- STEAM(coal)	PM10	1000 lbs	0.0480	Assume PM10 is equivalent to PM
		SO2	1000 lbs	1.800	AP-42, 9/98, Table 1.4-1, 0.8% sulfur
		CO	1000 lbs	0.147	Eng. StackTest Oct. 2009
		NOx	1000 lbs	1.10	Eng. Stack Test - Oct. 2009
		NOx	1000 lbs	0.55	2009 Eng. Stack Test & 50% removal (low Nox burners)
		VOC	1000 lbs	0.0042	AP-42, 9/98, Table 1.4-1
	B & W BOILER NO.2	PM	1000 lbs	2.60E-02	IDAPA 58.01.01.677 0.015 gr/dscf grain loading standard
	- STEAM (gas)	PM10	1000 lbs	2.60E-02	Assume PM10 is equivalent to PM
		SO2	1000 lbs	7.20E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.00E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	3.36E-01	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	6.60E-03	AP-42, 9/98, Table 1.4-2
S-B3	RILEY BOILER	PM	1000 lbs	0.057	Boiler MACT Limit (0.04 lb/MMBtu)
	- STEAM(coal)	PM10	1000 lbs	0.0496	Tier II Permit Limit (12.4 lb/h)
		SO2	1000 lbs	2.0	AP-42, 9/98, Table 1.4-1, 0.8% sulfur (subituminous)
		SO2	1000 lbs	1.7	AP-42, 9/98, Table 1.4-1, 0.8% sulfur(bituminous)
		CO	1000 lbs	1.20E-01	Eng. Stack Test - Oct. 2009
		NOx	1000 lbs	1.53	Eng. Stack Test - Oct. 2009
		NOx	1000 lbs	0.0588	Tier II Permit Limit (147 lb/h & 60.7 % reduction)
		VOC	1000 lbs	0.0079	AP-42, 9/98, Table 1.4-1
	RILEY BOILER	PM	1000 lbs	3.00E-02	IDAPA 58.01.01.677 0.015 gr/dscf grain loading standard
	- STEAM (gas)	PM10	1000 lbs	3.00E-02	Assume PM10 is equivalent to PM
		SO2	1000 lbs	8.60E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.20E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	4.00E-01	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	7.90E-03	AP-42, 9/98, Table 1.4-2
S-B4	UNION BOILER	PM	1000 lbs	2.60E-02	IDAPA 58.01.01.677 0.015 gr/dscf grain loading standard
	- STEAM (gas)	PM10	1000 lbs	6.80E-03	Assume PM10 is equivalent to PM
		SO2	1000 lbs	7.20E-04	AP-42, 9/98, Table 1.4-2
		CO	1000 lbs	1.10E-01	AP-42, 9/98, Table 1.4-1
		NOx	1000 lbs	1.20E-01	AP-42, 9/98, Table 1.4-1
		VOC	1000 lbs	6.60E-03	AP-42, 9/98, Table 1.4-2

EMISSION FACTOR SUMMARY - PULP DRYING AND PELLETIZING
11/5/2015

NO.		POLLUTANT	UNIT	EMISSION FACTOR LB/UNIT	REFERENCE
S-D1	SOUTH DRYER	PM	Tons	0.62	Nov. 2002 Stack Test
	-TOTAL INPUT	PM10	Tons	0.62	Assume PM10 is equivalent to PM
		SO2	Tons	0.15	Eng. Test Dec 2001
		CO	Tons	5.86	Eng. Test Dec 2001
		NOx	Tons	1.58	Eng. Test Dec 2001
		VOC	Tons	0.036	Eng. Source Test
S-D2	CENTER DRYER	PM	Tons	0.58	Nov. 2002 Stack Test
	-TOTAL INPUT	PM10	Tons	0.58	Assume PM10 is equivalent to PM
		SO2	Tons	0.15	Eng. Test Dec 2001
		CO	Tons	5.86	Eng. Test Dec 2001
		NOx	Tons	1.58	Eng. Test Dec 2001
		VOC	Tons	0.036	Eng. Source Test
S-D3	NORTH DRYER	PM	Tons	0.87	Nov. 2002 Stack Test
	-TOTAL INPUT	PM10	Tons	0.87	Assume PM10 is equivalent to PM
		SO2	Tons	0.15	Eng. Test Dec 2001
		CO	Tons	5.86	Eng. Test Dec 2001
		NOx	Tons	1.58	Eng. Test Dec 2001
		VOC	Tons	0.036	Eng. Source Test
S-D3	Pellet Cooler	PM	lbs/h	0.80	1/04 Source Test & 25% safety factor
	Baghouse	PM10	lbs/h	0.80	1/04 Source Test & 25% safety factor

EMISSION FACTOR SUMMARY - LIME KILN AND CO2 PRODUCTION
Nampa Facility
11/5/2015

NO.		POLLUTANT	UNIT	EMISSION FACTOR [1] LB/UNIT	REFERENCE
S-K1	A LIME KILN - LIME ROCK	PM	Tons	0.090	12/03 Source Test
		PM10	Tons	0.090	12/03 Source Test
		CO	Tons	55.6	Eng. Stack Test Dec. 2003
		NOx	Tons	0.630	AP-42, Boiler Table 1.2-1, anthracite coal
	-COKE	SO2	Tons	0.40	AP-42, Table 1.4-2, & 99% removal
		VOC	Tons	0.582	Eng. est. based on 2005 TF Stack Test
S-K2	B LIME KILN	PM	Tons	0.090	12/03 Source Test
	- LIME ROCK	PM10	Tons	0.090	12/03 Source Test
		CO	Tons	55.6	Eng. Stack Test Dec. 2003
		NOx	Tons	0.630	AP-42, Boiler Table 1.2-1, anthracite coal
	-COKE	SO2	Tons	0.4	AP-42, Table 1.4-2, & 99% removal
		VOC	Tons	0.582	Eng. est. based on 2005 TF Stack Test
S-K3	LIME KILN MATERIAL	PM	Tons	0.0514	Engineering Estimate
	HANDLING BAGHOUSE	PM10	Tons	0.0514	Engineering Estimate
S-K4	PROCESS SLAKERS	PM	lbs/h	1.4	Tier I and Tier II Permit Limits
	-CaO	PM10	lbs/h	1.4	Tier I and Tier II Permit Limits

EMISSION FACTOR SUMMARY - SUGAR WAREHOUSE AND SHIPPING
Nampa Facility
11/5/2015

NO.		POLLUTANT	UNIT	EMISSION FACTOR [1] LB/UNIT	REFERENCE
S-W1	DRYING GRANULATOR				
	- SUGAR	PM	lbs/h	1.1	Tier I and Tier II Permit Limits
		PM10	lbs/h	1.1	Tier I and Tier II Permit Limits
S-W2	NO. 1 COOLING GRANULATOR	PM	lbs/h	0.3	Tier I and Tier II Permit Limits
	- SUGAR	PM10	lbs/h	0.3	Tier I and Tier II Permit Limits
S-W3	NO. 2 COOLING GRANULATOR				
	- SUGAR	PM	lbs/h	0.3	Tier I and Tier II Permit Limits
		PM10	lbs/h	0.3	Tier I and Tier II Permit Limits
S-W4	SUGAR HANDLING (PROCESS #2)	PM	lbs/h	0.3	Tier I and Tier II Permit Limits
		PM10	lbs/h	0.3	Tier I and Tier II Permit Limits
S-W6	SUGAR HANDLING (SPECIALTIES)	PM	lbs/h	0.1	Tier I and Tier II Permit Limits
		PM10	lbs/h	0.1	Tier I and Tier II Permit Limits
S-W7	SUGAR HANDLING (PACK. LINE)	PM	lbs/h	0.2	Tier I and Tier II Permit Limits
		PM10	lbs/h	0.2	Tier I and Tier II Permit Limits

EMISSION FACTOR SUMMARY - OTHER SOURCES
Nampa Facility
11/5/2015

NO.		POLLUTANT	UNIT	EMISSION FACTOR [1] LB/UNIT	REFERENCE
S-O5	MAIN MILL	VOC	1000 gal	0.277	2005 Beet Campaign - Non Validated Test Method
S-O2	A - SIDE SULFUR STOVE	SO2	lb/ton	101.64	July 1992 Eng Stack Test @ Nampa , 20% safety factor
S-O3	B - SIDE SULFUR STOVE	SO2	lb/ton	101.64	July 1992 Eng Stack Test @ Nampa , 20% safety factor

PARTICULATE MATTER EMISSION FACTORS
Updated November 2015
Nampa Facility

1.a. B&W BOILER NO. 1 (S-B1 Coal) and B&W BOILER NO. 2 (S-B2 Coal)

The emissions factor is based on the 0.04 lb/MMBtu/hr Boiler MACT Limit. The maximum capacity of each boiler is 126 MMBtu/h or 6.4 tons coal/h (105,000 lbs steam/hr).

0.04 lb/MMBtu/h x 126 MMBtu/h = 5.04 lbs/h

(5.04 lb/hr)/(105 Klbs/h) = **0.048 lbs/Klbs steam**

2. B&W BOILER NO. 1 (S-B1 Nat. Gas) and B&W BOILER NO. 2 (S-B2 Nat. Gas)

The permit limit based on IDAPA 58.01.01.677 for this boiler is **0.015 grains/dscf** corrected at 3% O_2. Maximum capacity of the boiler is 105,000 lbs steam/hr, 126 MMBtu input/hr and a maximum of $0.126x10^6$ cu ft/hr. Heat content of natural gas is 1000 Btu/ft^3, heat content of steam is 960 Btu/lb steam and efficiency of the boiler is 80%. Maximum stack gas flow, from 40 CFR 60 Appendix A Method 19, for natural gas combustion, adjusted at 3% O_2 is:

105,000 lb steam/hr x 1/0.8 x 960 x 1/1000 = $0.126x10^6$ ft^3/hr

1,000 Btu/ft^3 x $0.126x10^6$ ft^3/hr /10^6 = 126 MMBtu/hr

Fd = (8710 dscf/MMBtu)(20.9/(20.9 - 3)) = 10,170 dscf/MMBtu at 3%O2

10,170 dscf/MMBtu x 126 MMBtu/hr x 1hr/60 min = 21,357 dscf/min

0.015 grains/dscf x 21,357 dscf/min x 60 min/hr x1lb/7000 grains = 2.75 lb/hr

The emission factor is:

(2.75 lb/hr) / (105 Klbs/h) = **0.026 lb/Klbs lb steam**

3.a. RILEY BOILER (S-B3) Permit Limits – Coal

The emissions factor is based on the 0.04 lb/MMBtu/hr Boiler MACT Limit. The maximum capacity the boiler is 358 MMBtu/h or 17.8 tons coal/h (250,000 lbs steam/hr).

0.04 lb/MMBtu/h x 358 MMBtu/h = 14.32 lbs/h

(14.32 lb/hr)/(250 Klbs/h) = **0.057 lbs/Klbs3 steam**

4. RILEY BOILER (S-B3) Permit Limits – Natural Gas

The permit limit based on IDAPA 58.01.01.677 for this boiler is 0.015 grains/dscf corrected at 3% O_2. Maximum capacity of the boiler is 250,000 lbs steam/hr, 358 MMBtu input/hr and a maximum of 0.358 x ^{106} cu. ft./hr. The natural gas heat content is 1,000 Btu/cu. ft., steam heat content is 1,145 Btu/lb steam and boiler efficiency is 80%. Maximum stack gas flow from 40 CFR 60 Appendix A Method 19, for natural gas combustion, adjusted to 3% O_2 is:

250,000 lb steam/hr / 0.8 x 1145 Btu/lb steam /1,000 Btu/ft^3 = 0.358x10^6 ft^3/hr

1,000 Btu/ft^3 x 0.358 x 10^6 /hr /10^6 = 358 MMBtu/hr

Fd = 8,710 dscf/MMBtu (20.9/(20.9 – 3)) = 10,170 dscf/MMBtu at 3% O_2

10,170 dscf/MMBtu x 358 MMBtu/hr x 1 hr/60 min = 60,681 dscf/min

0.015 grain/dscf x 60,681 dscf/min x 60 min/hr x 1 lb/7,000 grains = 7.8 lb/hr

The emission factor is:

(7.8 lb/hr)/(250 Klbs/h) = **0.03 lb/Klbs lb steam**

5. UNION BOILER (S-B4) Permit Limits – Natural Gas

The permit limit based on IDAPA 58.01.01.677 for this boiler is 0.015grains/dscf corrected at 3% O_2. Maximum capacity of the boiler is 60,000 lbs steam/hr, 72 MMBtu input/hr and a maximum of 0.075 x10^6 ft^3/hr. The natural gas heat content is 1000 Btu/ft^3, steam heat content is 960 Btu/lb steam and efficiency of the boiler is 80%. Maximum stack gas flow, from 40 CFR 60 Appendix A Method 19, for natural gas combustion, adjusted at 3% O_2 is:

60,000 lb steam/hr / 0.8 x 960 Btu/lb steam /1,000 Btu/ft^3 =0.072x10^6 ft^3/hr

1,000 Btu/ft^3 x 0.072x10^6 ft^3/hr /10^6 = 72 MMBtu/hr

Fd = (8710 dscf/MMBtu) (20.9/(20.9 – 3)) = 10,170dscf/MMBtu at 3%O2

10,170 dscf/MMBtu x 72 MMBtu/hr x 1hr/60 min = 12,204 dscf/min

0.015 grains/dscf x 12,204 dscf/min x 60 min/hr x1lb/7000 grains = 1.57 lb/hr

The emission factor is:

(1.57 lb/hr)/(60 Klbs/h) = **0.026 lb/Klbs lb steam**

6. PELLET COOLER BAGHOUSE (S-D9)

Compliance testing on January 15, 2004 and include front and back half PM emissions. The measured emissions were 0.636 lbs/h. Assume a 25% safety factor then:

(0.636 lbs/h) (1.25) = 0.08 lbs/h

7. A LIME KILN (S-K1) – Coal/Coke

The PM emissions factor was based on engineering estimates utilizing a source test conducted in 2003. The source test was conducted on the outlet of the lime kiln bypass cartridge baghouse. It is assumed that 25% of the exhaust gases from the kilns pass through the bypass baghouse. The remaining exhaust gases are vented through 1st and 2nd carbonation gas washers and then to tanks. The controlled lime kiln EF is 0.09 lbs PM_{10} per ton lime rock and calculated as follows:

396	=	tons per day limerock
16.5	=	tons per hour limerock
0.37	=	lbs PM_{10} per hour – Controlled after baghouse
25	=	% flow through bypass vent – Assume
1.48	=	lbs PM_{10} per hour – Estimated total emissions from all controlled emissions points. Assume gas washers, CO_2 compressor and carb vents have similar control efficiencies as a baghouse.
0.09	=	**lbs PM_{10} per ton limerock – Controlled Kiln EF**

8. B LIME KILN (S-K2) Permit Limits

Same as A Lime Kiln (S-K1) = **0.09 lbs PM_{10} per ton limerock**

9. LIME KILN BUILDING MATERIAL HANDLING (S-K3)

Compliance testing on November 12, 2005 include front and back half PM emissions. Based on this data the emissions factors are as follows:

Front Half	0.778 lb/hr
Back Half	0.183 lb/hr
Total PM	**0.961 lb/hr**

Based on limerock throughput of 16.5 t/hr., the emission factor is

EF = 0.961 / 16.5 = **0.0582 lbs. PM 10 / ton limerock**

10. A&B PROCESS SLAKERS (S-K4)

PM and PM_{10} emissions are based on the Tier I (No. T1-050020) and Tier II (T2-050020) Operating Permit limits of 1.4 lbs PM_{10} /hr and 6.1 tons PM_{10} /yr.

11. DRYING GRANULATOR (S-W1)

PM and PM_{10} emissions are based on the Tier I (No. T1-050020) and Tier II (T2-050020) Operating Permit limits of 1.1 lbs PM_{10} /hr and 5.0 tons PM_{10} /yr.

12. #1 COOLING GRANULATOR (S-W2)

PM and PM_{10} emissions are based on the Tier I (No. T1-050020) and Tier II (T2-050020) Operating Permit limits of 0.3 lbs PM_{10} /hr and 1.3 tons PM_{10} /yr.

13. #2 COOLING GRANULATOR (S-W3)

Same as #1 Cooling Granulator (S-W2)

14. SUGAR HANDLING (Process #2) (S-W4)

PM and PM_{10} emissions are based on the Tier I (No. T1-050020) and Tier II (T2-050020) Operating Permit limits of 0.3 lbs PM_{10} /hr and 1.2 tons PM_{10} /yr.

15. SUGAR HANDLING (SPECIALITIES) (S-W6)

PM and PM_{10} emissions are based on the Tier I (No. T1-050020) and Tier II (T2-050020) Operating Permit limits of 0.1 lbs PM_{10} /hr and 0.6 tons PM_{10} /yr.

16. SUGAR HANDLING (Retail Packaging Line) (S-W7)

PM and PM_{10} emissions are based on the Tier I (No. T1-050020) and Tier II (T2-050020) Operating Permit limits of 0.2 lbs PM_{10} /hr and 0.9 tons PM_{10} /yr.

SULFUR DIOXIDE (SO_2) EMISSION FACTORS
Updated November 2015
Nampa Facility

1.a. B&W BOILER NO. 1 and NO. 2(S-B1 and S-B2) – Coal

Subbituminous (9900 Btu/lb)
From AP-42, table 1.1-1 for subbituminous coal combustion, for pulverized coal-fired, dry bottom, SO_2 emission factor is 35, multiplied by 0.8 (0.8% S by weight, in the coal), 28 lb/ton. Heat content of coal is 9,900 BTU/lb coal, heat content of steam is 960 BTU/lb steam and efficiency of the boiler is 80%.

(28 lbs/ton coal) (1 ton/2000 lbs)(1/(9900)(10^6/MMBtu) = 1.4 lb/MMBTU

(1.4 lb/MMBtu)(1/0.80)(9.60 x 10^{-4} MMBtu/lb steam)(1000 lb/Klbs steam) =
1.8 lb/Klbs lb steam

Bituminous (12000 Btu/lb)
From AP-42, table 1.1-1 for subbituminous coal combustion, for pulverized coal-fired, dry bottom, SO_2 emission factor is 38, multiplied by 0.8 (0.8% S by weight, in the coal) 30lb/ton. Heat content of coal is 12,000 BTU/lb coal, heat content of steam is 960 BTU/lb steam and efficiency of the boiler is 80%.

(30 lbs/ton coal) (1 ton/2000 lbs)(1/(12000)(10^6/MMBtu) = 1.25 lb/MMBTU

(1.25 lb/MMBtu)(1/0.80)(9.60 x 10^{-4} MMBtu/lb steam)(1000 lb/Klbs steam) =
1.5 lb/Klbs lb steam

1.b. B&W BOILER NO. 1 and NO. 2(S-B1 and S-B2) – Natural Gas

From AP-42 (7/98), Table 1.4-2 for natural gas combustion, for utility boilers, SO_2 emission factor is 0.6 lb/10^6 ft^3. Heat content of natural gas is 1000 BTU/ ft^3, heat content of steam is 960 BTU/lb steam and efficiency of the boiler is 80%.

(0.6 lb/10^6 ft^3)(1 ft^3/1000Btu)(10^6 Btu/MMBtu) = 0.0006 lbs/MMBtu

(0.0006 lb/MMBtu)(1/0.80)(960 x 10^{-4} MMBtu/lb steam)(1000 lbs/Klbs steam) =
0.00072 lb/Klbs lb steam

2.a. RILEY BOILER (S-B3) – Coal

Subbituminous (9900 Btu/lb)
From AP-42, Table 1.1-1 for subbituminous coal combustion, for pulverized coal-fired, dry bottom, SO_2 emission factor is 35, multiplied by 0.8 (0.8% S by weight, in the coal), 28 lb/ton. Heat content of coal is 9,900 BTU/lb coal, heat content of steam is 1145 BTU/lb steam and efficiency of the boiler is 80%.

$$(28 \text{ lb/ton coal})(1 \text{ ton}/2000 \text{ lbs})(1/9900)(10^6/\text{MMBtu}) = 1.4 \text{ lbs/MMBtu}$$

$$(1.4 \text{ lb/MMBtu})(1/0.80)(1.145 \times 10^{-3} \text{ MMBtu/lb steam})(1000 \text{ lb/Klbs steam}) =$$
2.0 lb/Klbs lb steam

Bituminous (12000 Btu/lb)
From AP-42, Table 1.1-1 for subbituminous coal combustion, for pulverized coal-fired, dry bottom, SO_2 emission factor is 38, multiplied by 0.75 (0.75% S by weight, in the coal), 28.5 lb/ton. Heat content of coal is 12000 BTU/lb coal, heat content of steam is 1145 BTU/lb steam and efficiency of the boiler is 80%.

$$(28.5 \text{ lb/ton coal})(1 \text{ ton}/2000 \text{ lbs})(1/12000)(10^6/\text{MMBtu}) = 1.19 \text{ lbs/MMBtu}$$

$$(1.19 \text{ lb/MMBtu})(1/0.80)(1.145 \times 10^{-3} \text{ MMBtu/lb steam})(1000 \text{ lb/Klbs steam}) =$$
1.70 lb/Klbs lb steam

2.b. RILEY BOILER (S-B3) – Natural Gas

From AP-42, table 1.4-1 for natural gas combustion, for utility boilers, SO_2 emission factor is 0.6 lb/10^6 ft^3 NG. Heat content of natural gas is 1000 BTU/ft^3, heat content of steam is 1145 BTU/lb steam and efficiency of the boiler is 80%.

$$(0.6 \text{ lb}/10^6 \text{ ft}^3)(1 \text{ ft}^3/1000\text{Btu})(10^6 \text{ Btu/MMBtu}) = 0.0006 \text{ lbs/MMBtu}$$

$$(0.0006 \text{ lb/MMBtu})(1/0.80)(1.145 \times 10^{-3} \text{ MMBtu/lb steam})(1000 \text{ lbs/Klbs steam})=$$
0.00086 lb/Klbs lb steam

3. UNION BOILER (S-B4) – Natural Gas

From AP-42, Table 1.4-1 for natural gas combustion, for utility boilers, SO_2 emission factor is 0.6 lb/10^6 ft^3 NG. Heat content of natural gas is 1000 BTU/ ft^3, heat content of steam is 960 BTU/lb steam and efficiency of the boiler is 80%.

$$(0.6 \text{ lb}/10^6 \text{ ft}^3)(1 \text{ ft}^3/1000\text{Btu})(10^6 \text{ Btu/MMBtu}) = 0.0006 \text{ lbs/MMBtu}$$

$$(0.0006 \text{ lb/MMBtu})(1/0.80)(960 \times 10^{-4} \text{ MMBtu/lb steam})(1000 \text{ lbs/Klbs steam}) =$$
0.00072 lb/Klbs lb steam

4. A LIME KILN (S-K1) – Coke

SO_2 emissions from the lime kiln systems at sugar beet processing facilities are very low. SO_2 emissions from coal or coke fueled kilns are reduced significantly due to the gas washers, water ring compressors and carbonation tanks. The high pH of the scrubbing water in the gas washers and water ring compressors, promotes SO_2 removal. In addition, high pH milk of lime in the carbonation tanks can further reduce SO_2 emissions. For coke or coal, SO_2 emissions are estimated using a mass balance approach. Controlled emission factors were based on a 99% removal efficiency for the gas washers, water ring compressors and carbonation tanks. Based on

EPA AP-42 Table 1.4-2 and a 99% removal efficiency, the emissions factor is 0.4 lbs SO_2/ton coke.

5. B LIME KILN (S-K2) – Coke

Same as A Lime Kiln. (S-K1)) = **<u>0.4 lbs. SO_2/ ton coke</u>**

6. A SIDE SULFUR STOVE (S-O2)

Preliminary uncertified SO_2 stack tests were conducted on B-side sulfur tower at the Nampa facility in July 1992. The purpose of the testing was to obtain a rough estimate of the SO_2 emissions from the sulfur towers since there are no EPA AP-42 emission factors for this emission source. EPA testing methods were generally followed during the testing sampling. The sulfur stove can operate with and without a fan. SO_2 emissions were higher with the fan operating. As a worst-case scenario, the emission factor utilized is for a sulfur stove with a fan operating at all times.

Assuming a 20% safety factor, the sulfur stove emission factor becomes:

(84.7 lbs SO_2 /ton sulfur) (1.2) = **<u>101.64 lbs SO_2/ton sulfur</u>.**

7. B SIDE SULFUR STOVE (S-O3)

Same as 'A' Side Sulfur Stove= **<u>101.64 lbs SO_2/ton sulfur</u>.**

CARBON MONOXIDE (CO) EMISSION FACTORS
Updated November 2015
Nampa Facility

1.a. B&W BOILER NO. 1 and NO. 2 (S-B1 & S-B2) – Coal

The CO emission factor is based on engineering stack tests conducted by CCI Environmental on the No. 1 and No. 2 B&W boiler(s) at the Nampa facility on October 14, 2009. The emissions factor is as follows:

$$(26.0 \text{ lbs/h})(1/177 \text{ Klbs/h}) = 0.147 \text{ lbs CO/Klbs steam}$$

1.b. B&W BOILER NO. 1 and NO. 2 (S-B1 & S-B2) – Natural Gas

From AP-42, Table 1.4-2 for natural gas combustion, for utility boilers, CO emission factor is 84 lb/10^6 ft^3. Heat content of natural gas is 1000 Btu/ft^3, heat content of steam is 960 Btu/lb steam and efficiency of the boiler is 80%.

$$(84 \text{ lb}/10^6 \text{ ft}^3)(1 \text{ ft}^3/1000\text{Btu})(10^6 \text{ Btu/MMBtu}) = 0.084 \text{ lb/MMBtu}$$

$$(0.084 \text{ lb/MMBtu})(1/0.80)(9.60 \times 10^{-4} \text{ MMBtu/lb steam})(1000 \text{ lbs/Klbs steam}) = \underline{\mathbf{0.10 \text{ lb/Klbs steam}}}$$

2.a. RILEY BOILER (S-B3) – Coal

The CO emission factor is based on engineering stack tests conducted by CCI Environmental on the Riley boiler(s) at the Nampa facility on October 15, 2009. The emissions factor is as follows:

$$(0.53 \text{ lbs/h})(1/227 \text{ Klbs/h}) = 2.33 \times 10^{-3} \text{ lbs CO/Klbs steam}$$

2.b. RILEY BOILER (S-B3) – Natural Gas

From AP-42, Table 1.4-2 for natural gas combustion, for utility boilers, CO emission factor is 84 lb/10^6 ft^3. Heat content of natural gas is 1000 Btu/ft^3, heat content of steam is 1145 Btu/lb steam and efficiency of the boiler is 80%.

$$(84 \text{ lb}/10^6 \text{ ft}^3)(1 \text{ ft}^3/1000\text{Btu})(10^6 \text{ Btu/MMBtu}) = 0.084 \text{ lb/MMBtu}$$

$$(0.084 \text{ lb/MMBTU})(1.145 \times 10^{-3} \text{ MMBtu/lb steam})(1000 \text{ lbs/Klbs steam}) = \underline{\mathbf{0.12 \text{ lb/Klbs steam}}}$$

3. UNION BOILER (S-B4) – Natural Gas

From AP-42, Table 1.4-1 for natural gas combustion, for industrial boilers, CO emission factor is 84 lb/10^6 ft^3. Heat content of natural gas is 1000 Btu/ ft^3, heat content of steam is 960 Btu/lb steam and efficiency of the boiler is 80%.

$(84\ lb/10^6\ ft^3)(1\ ft^3/1000Btu)(10^6\ Btu/MMBtu) = 0.084\ lb/MMBtu$

$(0.084\ lb/MMBtu)(1/0.80)(9.60 \times 10^{-4}\ MMBtu/lb\ steam)(1000\ lbs/Klb\ steam) =$
0.10 lb/Klbs steam

4. A LIME KILN (S-K1) – Coke

The CO emission factor for the lime kiln system is based on a December 2003 source test. Based on this source test, the overall emission factor for the lime kiln system is (916.5 lbsCO/h)/(16.5 tns lime rock) = **55.6 lbs. CO / ton limerock**.

CO emissions from the lime kiln system are vented from (3) points (Lime Kiln Baghouse Vent, 1st and 2nd Carbonation Tanks). Based on the 2003 source tests, the distribution of CO is as follows:

CO distribution from the Lime Kiln System

Lime Kiln A (S-K1)	29%
Lime Kiln B (S-K2)	
1st Carbonation Tank	56%
2nd Carbonation Tank (A-Side)	9%
2nd Carbonation Tank (B-Side)	6%

Note: S-K1 & S-K2 have a common emission point (baghouse vent).

5. B LIME KILN (S-K2) – Coke

Same as A Lime Kiln (S-K1) = **55.6 lbs/ton limerock**

NITROGEN OXIDE (NO_x) EMISSION FACTORS
Updated November 2015
Nampa Facility

1.a. B&W BOILER NO. 1 & NO. 2 (S-B1 & S-B2) – Coal

The NO_x emission factor is based on engineering stack tests conducted by CCI Environmental on the No.1 and No. 2 B&W boilers(s) at the Nampa facility on October 14, 2009. The emissions factor is as follows:

(194 lbs/h)(1/177 Klbs/h) = 1.10 lbs NO_x/Klbs steam

1.b. B&W BOILER NO. 1 & NO. 2 (S-B1 & S-B2) – Natural Gas

From AP-42, Table 1.4-1 for natural gas combustion, for utility boilers, NO_x emission factor is 280 lb/10^6 ft^3. Heat content of natural gas is 1000 Btu/ft^3, heat content of steam is 960 Btu/lb steam and efficiency of the boiler is 80%.

(280 lb/10^6 ft^3)(1 ft^3/1000Btu)(10^6 Btu/MMBtu) = 0.28 lb/MMBtu

(0.28 lbs/MMBtu)(1/0.80)(960 x 10^{-4} MMBtu/lb steam)(1000 lbs/Klbs steam) = **0.336 lb/Klbs steam**

2.a. RILEY BOILER (S-B3) – Coal

The NO_x emission factor is based on engineering stack tests conducted by CCI Environmental on the Riley boiler(s) at the Nampa facility on October 15, 2009. The emissions factor is as follows:

(347 lbs/h)(1/227 Klbs/h) = 1.53 lbs NO_x/Klbs steam

2.b. RILEY BOILER (S-B3) – Natural Gas

From AP-42, table 1.4-1 for natural gas combustion, for utility boilers, NO_x emission factor is 280 lb/10^6 ft^3. Heat content of natural gas is 1000 Btu/ft^3, heat content of steam is 1145 Btu/lb steam and efficiency of the boiler is 80%.

(280 lb/10^6 ft^3)(1 ft^3/1000Btu)(10^6 Btu/MMBtu) = 0.28 lbs/MMBtu

(0.28 lbs/MMBtu)(1/0.80)(1.145 x 10^{-3} MMBtu/lb steam)(1000 lbs/Klbs steam) = **0.40 lb/Klbs steam**

3. UNION BOILER (S-B4) – Natural Gas

From AP-42, Table 1.4-1 for natural gas combustion, for industrial boilers, NO_x emission factor is 100 $lb/10^6\ ft^3$ (boiler with less than 100 MMBtu/hr heat input). Heat content of natural gas is 1000 Btu/ft^3, heat content of steam is 960 Btu/lb steam and efficiency of the boiler is 80%.

$$(100\ lb/10^6\ ft^3)(1\ ft^3/1000Btu)(10^6\ Btu/MMBtu) = 0.10\ lbs/MMBtu$$

$$(0.10\ lbs/MMBtu)(1/0.80)(960 \times 10^{-4}\ MMBtu/lb\ steam)(1000\ lbs/Klbs\ steam) = \underline{\mathbf{0.120\ lb/Klbs\ steam}}$$

4. A LIME KILN (S-K1) – Coke

The NO_x emission factor for the lime kiln is based on a permitting evaluation conducted at the Mini Cassia facility. For this evaluation, an EPA AP-42 emissions factor for spreader stoker boilers firing anthracite coal, Table 1.2-1 was selected. The emission factor expressed in terms of coal and limerock is as follows:

$$9\ lbs/ton\ coal \times 0.32\ tons\ coal/4.6\ tons\ limerock = 0.63\ lbs\ NO_x/ton\ limerock$$

5. B LIME KILN (S-K2) – Coke

Same as A Lime Kiln (S-K1) = 0.63 lbs NO_x/ton limerock

VOLATILE ORGANIC COMPOUNDS (VOC) EMISSION FACTORS
Updated November 2015
Nampa Facility

1.a. B&W BOILER NO.1 & NO.2 (S-B1 & S-B2) – Coal

From AP-42, Table 1.1-1 for subbituminous coal combustion, for pulverized coal-fired, dry bottom, VOC emission factor is 0.07 lb/ton. Heat content of coal is 9,900 Btu/lb coal, heat content of steam is 960 Btu/lb steam and efficiency of the boiler is 80%.

$$(0.07 \text{ lb/ton coal})(1 \text{ ton/2000 lbs})(1/(9900)(10^6/\text{MMBtu}) = 0.0035 \text{ lb/MMBtu}$$

$$(0.0035 \text{ lb/MMBtu})(1/0.80)(9.60 \times 10^{-4} \text{ MMBtu/lb steam})(1000 \text{ lb/Klbs steam}) =$$
0.0042 lb/Klbs steam

1.b. B&W BOILER NO.1 (S-B1) – Natural Gas

From AP-42, Table 1.4-2 for natural gas combustion, for utility boilers, VOC emission factor is 5.5 lb/10^6 ft^3. Heat content of natural gas is 1000 Btu/ft^3, heat content of steam is 960 Btu/lb steam and efficiency of the boiler is 80%.

$$(5.5 \text{ lb/}10^6 \text{ ft}^3)(1 \text{ ft}^3\text{/1000Btu})(10^6 \text{ Btu/MMBtu}) = 0.0055 \text{ lb/MMBtu}$$

$$(0.0055 \text{ lb/MMBtu})(1/0.80)(960 \times 10^{-4} \text{ MMBtu/lb steam})(1000 \text{ lbs/Klbs steam}) =$$
0.0066 lb/Klbs steam

2.a. RILEY BOILER (S-B3) – Coal

From AP-42, Table 1.1-1 for subbituminous coal combustion, for pulverized coal-fired, dry bottom, VOC emission factor is 0.07 lb/ton. Heat content of coal is 9,900 Btu/lb coal, heat content of steam is 1145 Btu/lb steam and efficiency of the boiler is 80%.

$$(0.07 \text{ lb/ton coal})(1 \text{ ton/2000 lbs})(1/9900)(10^6/\text{MMBtu}) = 0.0035 \text{ lb/MMBtu}$$

$$(0.0035 \text{ lb/MMBtu})(1/0.80)(1.145 \times 10^{-3} \text{ MMBtu/lb steam})(1000 \text{ lb/Klbs steam}) =$$
0.0051 lb/Klbs steam

2.b. RILEY BOILER (S-B3) – Natural Gas

From AP-42, Table 1.4-2 for natural gas combustion, for utility boilers, VOC emission factor is 5.5 lb/10^6 ft^3. Heat content of natural gas is 1000 Btu/ft^3, heat content of steam is 1145 Btu/lb steam and efficiency of the boiler is 80%.

$$(5.5 \text{ lb/}10^6 \text{ ft}^3)(1 \text{ ft}^3\text{/1000Btu})(10^6 \text{ Btu/MMBtu}) = 0.0055 \text{ lb/MMBtu}$$

$(0.0055 \text{ lb/MMBtu})(1.145 \times 10^{-3} \text{ MMBtu/lb steam})(1000 \text{ lbs/Klbs steam}) =$ **0.0079 lb/Klbs steam**

3. UNION BOILER (S-B4) – Natural Gas

From AP-42, table 1.4-2 for natural gas combustion, for utility boilers, VOC emission factor is 5.5 lb/10^6 ft^3. Heat content of natural gas is 1000 Btu/ft^3, heat content of steam is 960 Btu/lb steam and efficiency of the boiler is 80%.

$$(5.5\ lb/10^6\ ft^3)(1\ ft^3/1000Btu)(10^6\ Btu/MMBtu) = 0.0055\ lb/MMBtu$$

$$(0.0055\ lb/MMBtu)(1/0.80)(960 \times 10^{-4}\ MMBtu/lb\ steam)(1000\ lbs/Klbs\ steam) =$$

0.0066 lb/Klbs steam

4. A LIME KILN (S-K1) – Coke

There are no published VOC EF's in AP-42 fir vertical mixed shaft kilns. In addition, there are no EPA approved and field validated VOC testing procedures for emission sources at sugar beet processing facilities. VOC EF's for the kilns were estimated from engineering stack tests conducted on the 1st and 2nd carbonation tanks at the Twin Falls facility in October 2005. This data was submitted to IDEQ in June 2007. Based on this data, total VOC's are estimated to be 0.0953 lbs per ton coke and 0.524 lbs per ton anthracite coal.

5. B LIME KILN (S-K2) – Coke

Same as A Lime Kiln (S-K1).

6. MAIN MILL (S-O1)

There are no EPA approved and field validated VOC testing procedures for the main mill vents at sugar beet processing facilities. During the 2005 beet processing campaign, TASCO hired a third party consultant to conduct speciated VOC screening engineering stack tests on selected vents at the Mini-Cassia facility and Twin Falls facility. The 1st and 2nd carbonation tank vents were sampled at the Twin Falls facility in October 2005.

A stack with several evaporator heater vents was sampled at the Mini Cassia facility in October 2005 and March 2006.

Although emissions data was collected, several interferences and inaccuracies with the test methods were documented. Testing interferences, which affect the accuracy of the results, include high stack gas CO2 concentrations, high moisture stack gas moistures and entrained moisture. High moisture levels greatly reduced the sample times and volumes, which limited the ability to collect accurate and representative data. In order to more accurately measure these sources, the interferences would need to be eliminated or develop alternative-testing procedures.

However, based on an analysis of this data and other information TASCO will utilize the preliminary engineering stack testing at this time to estimate VOC's from the main mill vents. The emission factor is as follows:

0.277 lbs VOC's/1000 gals of juice

Section 6
Ambient Air Quality Impact Analysis

An ambient air quality impact analysis is not required for the firing of natural gas only in the No. 1 and No. 2 B&W boilers. First, except for short-term CO emissions, all other criteria pollutant emissions are expected to decrease when firing natural gas versus coal. However, the overall short-term facility-wide emissions are expected to decrease (including CO) when accounting for the shutdown of the coal-fired pulp dryers and future installation of low NO_x burners when the Riley boiler is fired with coal. As discussed in Section 4, long-term projected/permitted CO emissions are above baseline levels based on a conservative permitted evaluation. However, since there are no long-term NAAQS's for CO, modeling is not required.