Statement of Basis

Permit to Construct No. P-2011.0131
Project ID 62436

Shelley Facility of Basic American Foods, A Division of Basic American, Inc.
Shelley, Idaho

Facility ID 011-00020

Final

August 6,2020

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Permit Writer

The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

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ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

AAC	acceptable ambient concentrations
AACC	acceptable ambient concentrations for carcinogens
acfm	actual cubic feet per minute
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
BMP	best management practices
Btu	British thermal units
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CAS No.	Chemical Abstracts Service registry number
CEMS	continuous emission monitoring systems
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CI	compression ignition
CMS	continuous monitoring systems
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	CO_2 equivalent emissions
COMS	continuous opacity monitoring systems
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EL	screening emission levels
EPA	U.S. Environmental Protection Agency
FEC	Facility Emissions Cap
GHG	greenhouse gases
gph	gallons per hour
gpm	gallons per minute
HAP	hazardous air pollutants
HHV	higher heating value
hp	horsepower
hr/yr	hours per consecutive 12 calendar month period
ICE	internal combustion engines
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
km	kilometers
lb/hr	pounds per hour
m	meters
MACT	Maximum Achievable Control Technology
MMBtu	million British thermal units
MMscf	million standard cubic feet
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operation and maintenance
O_2	oxygen
PAH	polyaromatic hydrocarbons
PC	permit condition
PCB	polychlorinated biphenyl
PM	particulate matter

$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
POM	polycyclic organic matter
ppm	parts per million
ppmw	parts per million by weight
PSD	Prevention of Significant Deterioration
PTC	permit to construct
PTC/T2	permit to construct and Tier II operating permit
PTE	potential to emit
PW	process weight rate
RAP	recycled asphalt pavement
RFO	reprocessed fuel oil
RICE	reciprocating internal combustion engines
Rules	*Rules for the Control of Air Pollution in Idaho*
scf	standard cubic feet
SCL	significant contribution limits
SIP	State Implementation Plan
SM	synthetic minor
SM80	synthetic minor facility with emissions greater than or equal to 80% of a major source threshold
SO_2	sulfur dioxide
SO_X	sulfur oxides
T/day	tons per calendar day
T/hr	tons per hour
T/yr	tons per consecutive 12 calendar month period
T2	Tier II operating permit
TAP	toxic air pollutants
TEQ	toxicity equivalent
T-RACT	Toxic Air Pollutant Reasonably Available Control Technology
U.S.C.	United States Code
VOC	volatile organic compounds
yd^3	cubic yards
$\mu g/m^3$	micrograms per cubic meter

FACILITY INFORMATION

Description

The Basic American Foods (BAF) - Shelley plant includes a food drying and dehydrating plant. The Shelley plant produces dehydrated food products using a variety of drying and dehydration processes. Products are dried by contact with heated air. Drying air is heated either by direct-firing with natural gas or indirectly using steam heat exchangers. Air suspension unit processes are also used to classify materials and to remove unsuitable fractions from the production stream. Steam for plant operations is provided by boiler number 4, and a temporary boiler.

Materials transport occurs both internally within a processing activity and externally to transfer materials between processes, to place them into or take them out of bulk storage, or to transport them to packaging and load-out activities. BAF uses air suspension systems to transport granules and most formulated products; these suspension processes include air slides and pneumatic bulk transfer operations. BAF also uses belt and bucket conveyors at various locations in its operations to transport raw materials, products in processing, and finished products. All bucket and belt conveyors are entirely contained within enclosed buildings. BAF also uses wet flumes to transport raw potatoes. Forklifts are used to transfer tote containers within the plant. Materials recovery units (primarily cyclones) are integral to the operation of all unit processes in which granules or formulated products are suspended in air.

BAF operates packaging equipment to fill product containers with bulk product. Spices and flavoring may be added to the bulk product during the packaging process. Dust pickups located within the packaging area exhaust to the atmosphere through baghouses.

Raw materials are received on site by truck. Granules can be received by rail as well as by truck. All shipments are by rail or truck. Trucks are also used to move potatoes to and from the onsite cellars.

Plant products are described as follows.

Dehydrated potato granules

Potato granules are individual potato cells prepared from raw potatoes by cooking, followed by gentle drying. Granules typically range from 50 to 120 microns in size. Most of the granules produced at the Shelley Plant are used at the Shelley Plant; occasionally granules are shipped to other BAF plants for use in products produced at those plants.

Dehydrated potato flakes

Potato flakes are small flakes made of dehydrated, cooked potatoes. Flakes are typically 1/8 inch to 1/4 inch in diameter.

Dehydrated piece food products

BAF prepares dehydrated piece food products by dehydrating cooked and/or blanched foods. These foods can be either whole vegetables or vegetable pieces. Piece products range up to several inches in diameter.

Food processing byproducts

Sellable food fractions and off-specification materials that are not suitable for use in other products are produced as by-products of plant processes. BAF uses various materials classification processes to segregate, collect, and transport these byproducts. Food byproducts are transferred directly to load-out operations after collection without further processing beyond collection.

The Shelley facility uses a variety of drying and dehydration processes. Potato granules and dehydrated piece products are dried by contact with heated air. Drying air is heated either by direct-firing with natural gas or indirectly using steam heat exchangers. Air suspension unit processes are also used to classify materials and to remove unsuitable fractions from the production stream.

Potato flakes are produced by drying a thin film of cooked potatoes directly on a steam-heated drum. The heat from the drum evaporates the moisture from the flakes, producing a thin sheet of dried potatoes. This sheet is then broken and crushed to produce flake products.

Food processing by-products are produced from food fractions that are not suitable for sale as primary products.

Permitting History

The following information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A) or superseded (S).

May 2, 2019	P-2011.0131, project 62226, PTC revision to correct typographical errors (A).
September 25, 2014	T1-2013.0060, Tier I Operating Permit Renewal, Permit status (A), but will become (S) upon issuance of this permit.
October 4, 2012	T1-2007.0104, Tier I Operating Permit to incorporate a Permit to Construct P-2011.0131 project 60942 issued May 18, 2012, Permit status (S) after the Tier I permit T1-2013.0060 is issued.
December 29, 2017	P-2011.0131, Project 62226, PTC revision to include existing emission units left off of the PTC in the Tier II conversion to a PTC. Permit Status (S)
May 18, 2012	P-2011.0131, project 60942, converting the existing Tier II permit T2-2008.0145 into a Facilities Emissions Cap Permit to Construct. Permit status (S)
June 4, 2009	T2-2008.0145, Facility-wide Tier II operating permit and Permit to Construct with a Facility Emissions Cap (FEC), Permit status (S)
June 4, 2009	T1-2007.0104, Tier I permit renewal, Permit status (S)
February 11, 2003	PTC permit 011-00020, revised permit for ownership transfer from the Pillsbury Co. to Basic American Foods (it was determined that PTC No. 0140-0020 was never implemented and therefore expired two years after issuance), Permit status (S)
December 11, 2002	Tier I permit 011-00020, Incorporating PTC permits 0140-0020, incorporating PTC permits 0140-0020, issued March 20, 1990, and 011-0020, issued September 10, 2001, Permit status (S)
September 10, 2001	PTC permit 011-00020, A Permit to Construct for the ownership transfer from the Pillsbury Co. to Basic American Foods of Boilers 1, 3, and 4 and Flake Lines 2, 3, and 4, Permit status (S)
March 20, 1990	PTC permit 0140-0040, issued to the Pillsbury Co. for installing Boiler 4 and Flake Lines 2, 3, and 4, Permit status (S)
November 20, 1986	PTC permit 0140-0020 issued to the Pillsbury Co. for Boilers 1 and 3, Permit status (S)

Application Scope

This PTC is for a modification at an existing Tier I facility.

The applicant has proposed to:

- Remove boilers 1, 3, and 5
- Remove P6-1 dryer
- Remove P6-2 cooler
- Facility-Wide CO emission limit of 99 T/yr, changing the facility classification from A to SM80 and eliminating the requirements for a Tier I permit.

Application Chronology

February 20, 2020	DEQ sent a notice of violation to the facility, which included notification that a PTC was required (Enforcement Case No. E-2019.0015).
April 27, 2020	DEQ received an application and an application fee.
May 1, 2020	DEQ received an application fee.
June 1, 2020	DEQ determined that the application was complete.
June 11, 2020	DEQ made available the draft permit and statement of basis for peer and regional office review.
July 1, 2020	DEQ made available the draft permit and statement of basis for applicant review.
July 17, 2020	DEQ received the permit processing fee.
August 6, 2020	DEQ issued the final permit and statement of basis.

TECHNICAL ANALYSIS

Emissions Units and Control Equipment

Table 1 EMISSIONS UNIT AND CONTROL EQUIPMENT INFORMATION

ID No.	Source Description	Control Equipment Description	Emissions Point ID No. and Description
Boilers			
Boiler 4	Manufacturer: Cleaver-Brooks Model: DL-76-RH S/N: W-3511 (not labeled as S/N) Heat input rating: 72.1 MMBtu/hr Maximum steam production rate: 60,000 lb/hr Fuels: Natural Gas Date installed: 1990	None	See Appendix B
Temporary Boiler	Manufacturer: Cleaver-Brooks Model: NOS-2A-67-650-HC-NH S/N: RT-4477 Heat input rating: 98.6 MMBtu/hr Maximum steam production rate: 67,500 lb/hr Fuels: Natural Gas Date installed: 2017	None	See Appendix B
Process A			
P3-1	Dryer - 20 MMBtu/hr, natural gas-fired	None	See Appendix B
P3-2	Dryer - 0.5 MMBtu/hr, natural gas-fired	None	See Appendix B
P3-3	Material recovery unit	None	See Appendix B
P4-1	Dryer - 20 MMBtu/hr, natural gas-fired	None	See Appendix B
P4-2	Dryer - 0.5 MMBtu/hr, natural gas-fired	None	See Appendix B
P4-3	Material recovery unit	None	See Appendix B
P5-1	Purifier	None	See Appendix B
P5-2	Purifier	None	See Appendix B

ID No.	Source Description	Control Equipment Description	Emissions Point ID No. and Description
Process B			
P8-1	Dryer - Steam-heated	None	See Appendix B
P8-2	Dryer - Steam-heated	None	See Appendix B
P8-VE	Material recovery unit	None	See Appendix B
P8-VW	Material recovery unit	None	See Appendix B
P9-1	Dryer - Steam heated	None	See Appendix B
P10-1	Dryer - Steam heated	None	See Appendix B
P11-1	Dryer - Steam heated	None	See Appendix B
PKG-1	Material recovery unit on packaging line	None	See Appendix B
PKG-2	Material recovery unit on packaging line	None	See Appendix B
MT-2	Material recovery unit to animal feed storage	None	See Appendix B
MT-3	Material recovery unit to bulk storage	None	See Appendix B
Plant Heaters			
	Natural gas-fired space heaters	None	N/A

Emissions Inventories

Potential to Emit

IDAPA 58.01.01 defines Potential to Emit as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is state or federally enforceable. Secondary emissions do not count in determining the potential to emit of a facility or stationary source.

Using this definition of Potential to Emit an emission inventory was developed by BAF for the operations at the facility based off its most recent process modifications, Notice of Review of Ambient Concentration Analysis for modification to Stacks P6-1 and P6-2 (June 2010) and Notice of Review of Ambient Concentration Analysis for Restart of Process P8 (September 2011) included in Application for Conversion of Permit P-2011.0131 from FEC PTC to PTC provided by BAF and received by DEQ June 16, 2014. The emissions for the temporary boiler were based off of AP-42 chapter 1, section 1.4 (see Appendix A) associated with this proposed project. Emissions estimates for the temporary boiler of criteria pollutant, HAP PTE were based on operation of 7,008 hours per year, and process information specific to the facility for this proposed project.

Uncontrolled Potential to Emit

Using the definition of Potential to Emit, uncontrolled Potential to Emit is then defined as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall **not** be treated as part of its design **since** the limitation or the effect it would have on emissions **is not** state or federally enforceable.

The uncontrolled Potential to Emit is used to determine if a facility is a "Synthetic Minor" source of emissions. Synthetic Minor sources are facilities that have an uncontrolled Potential to Emit for regulated air pollutants or HAP above the applicable Major Source threshold without permit limits.

The following table presents the uncontrolled Potential to Emit for regulated air pollutants as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations and the assumptions used to determine emissions for each emissions unit. For this food processing operation uncontrolled Potential to Emit is based upon a worst-case for operation of the facility of 7,008 hr/yr (24 hr/day x 292 day/yr).

Table 2 UNCONTROLLED POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Emissions Unit	$PM_{10}/PM_{2.5}$ T/yr[b]	SO_2 T/yr[b]	NO_X T/yr[b]	CO T/yr[b]	VOC T/yr[b]
Point Sources					
Boiler 4	2.40	0.19	44.4	49.3	1.70
Temporary Boiler	0.2	0.3	31.1	16.0	2.3
P3-1	13.7	1.1	5.3	22.8	0.5
P3-2	0.4	0.1	0.1	0.6	-
P3-3	-	-	-	-	-
P4-1	13.7	1.1	5.3	22.8	0.5
P4-2	0.4	0.1	0.1	0.6	-
P4-3	-	-	-	-	-
P5-1	-	-	-	-	-
P5-2	-	-	-	-	-
P8-1N	0.6	0.2	-	-	-
P8-1S	0.6	0.2	-	-	-
P8-1A	0.1	-	-	-	-
P8-2N	0.6	0.2	-	-	-
P8-2S	0.6	0.2	-	-	-
P8-2A	0.1	-	-	-	-
P8-VE	0.3	-	-	-	-
P8-VW	0.3	-	-	-	-
P9-1	7.2	0.7	-	-	-
P10-1	7.2	0.7	-	-	-
P11-1	7.2	0.7	-	-	-
PKG-1	-	-	-	-	-
PKG-2	0.2	-	-	-	-
MT-2	0.3	-	-	-	-
MT-3	0.1	-	-	-	-
Heaters	1.0	0.31	12.8	10.7	0.7
Uncontrolled Totals	**57.7**	**6.01**	**99.3**	**122.6**	**5.7**

The following table presents the uncontrolled Potential to Emit for HAP pollutants as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations and the assumptions used to determine emissions for each emissions unit. For this food processing operation uncontrolled Potential to Emit is based upon a worst-case for operation of the facility of 7,008 hr/yr (24 hr/day x 292 day/yr). Then, the worst-case maximum HAP Potential to Emit was determined for this food processing operation.

Table 3 UNCONTROLLED POTENTIAL TO EMIT FOR HAZARDOUS AIR POLLUTANTS

Hazardous Air Pollutants	PTE (T/yr)
PAH	2.90E-04
POM	4.80E-06
Benzene	8.889E-04
Dichlorobenzene	5.08E-03
Formaldehyde	3.17E-02
Hexane	0.76
Toluene	1.43E-03
Arsenic	8.46E-05
Beryllium	5.09E-06
Cadmium	4.66E-04
Chromium	5.91E-04
Chromium (VI)	2.96E-05
Cobalt	3.55E-05

Hazardous Air Pollutants	PTE (T/yr)
Manganese	1.61E-04
Mercury	1.11E-04
Nickel	8.89E-04
Selenium	1.01E-05
Total	**0.80**

Pre-Project Potential to Emit

Pre-project Potential to Emit is used to establish the change in emissions at a facility as a result of this project.

The following table presents the pre-project potential to emit for all criteria pollutants from all emissions units at the facility from P-2011.0131 issued December 29, 2017 as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Table 4 PRE-PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Emissions Unit	$PM_{10}/PM_{2.5}$		SO_2		NO_X		CO		VOC	
	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]
Point Sources										
Boiler 1	0.29	1.3	0.02	0.09	3.87	16.95	3.25	14.2	0.21	0.92
Boiler 3	0.22	1.0	0.02	0.09	2.83	12.4	2.38	10.4	0.16	0.7
Boiler 4	0.55	2.4	0.13	0.74	10.16	44.4	11.26	49.2	1.28	5.6
Boiler 5	0.17	0.8	0.06	0.26	1.76	7.7	3.55	15.6	0.49	2.15
P3-1	3.12	13.7	0.29	1.26	1.22	5.3	5.2	22.8	0.11	0.47
P3-2	0.1	0.4	0.01	0.06	0.03	0.1	0.13	0.6	0.0	0.01
P3-3	0.01	0.0	0	0	0	0	0	0	0	0
P4-1	3.12	13.7	0.29	1.26	1.22	5.3	5.2	22.8	0.11	0.47
P4-2	0.1	0.4	0.01	0.06	0.03	0.1	0.13	0.6	0.0	0.01
P4-3	0.01	0.0	0	0	0	0	0	0	0	0
P5-1	0.02	0.0	0	0	0	0	0	0	0	0
P5-2	0.02	0.0	0	0	0	0	0	0	0	0
P6-1	1.3	5.7	0.3	1.31	2.50	11.0	10.33	46.7	0.22	0.97
P6-2	0.65	2.9	0.1	0.44	0	0	0	0	0	0
P8-1N	0.15	0.7	0.04	0.18	0	0	0	0	0	0
P8-1S	0.15	0.7	0.04	0.18	0	0	0	0	0	0
P8-1A	0.03	0.1	0	0	0	0	0	0	0	0
P8-2N	0.15	0.7	0.04	0.18	0	0	0	0	0	0
P8-2S	0.15	0.7	0.04	0.18	0	0	0	0	0	0
P8-2A	0.03	0.1	0	0	0	0	0	0	0	0
P8-VE	0.07	0.3	0	0	0	0	0	0	0	0
P8-VW	0.07	0.3	0	0	0	0	0	0	0	0
P9-1	1.65	7.23	0.17	0.73	0	0	0	0	0	0
P10-1	1.65	7.23	0.17	0.73	0	0	0	0	0	0
P11-1	1.65	7.23	0.17	0.73	0	0	0	0	0	0
PKG-1	0.0	0.0	0	0	0	0	0	0	0	0
PKG-2	0.1	0.4	0	0	0	0	0	0	0	0
MT-2	0.07	0	0	0	0	0	0	0	0	0
MT-3	0.02	0.1	0	0	0	0	0	0	0	0
Heaters	0.44	1.0	0.14	0.31	5.83	12.8	4.9	10.7	0.32	0.7
Pre-Project Totals	**16.06**	**69.09**	**2.04**	**8.79**	**29.45**	**116.05**	**46.33**	**193.6**	**2.9**	**12**

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.

Post Project Potential to Emit

Post project Potential to Emit is used to establish the change in emissions at a facility and to determine the facility's classification as a result of this project. Post project Potential to Emit includes all permit limits resulting from this project.

The following table presents the post project Potential to Emit for criteria pollutants from all emissions units at the facility as determined by P-2011.0131 issued December 29, 2017 and DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Table 5 POST PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Emissions Unit	$PM_{10}/PM_{2.5}$		SO_2		NO_X		CO[c]		VOC	
	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]
Point Sources										
Boiler 4	0.55	2.4	0.13	0.74	10.16	44.4	11.26	49.2	1.28	5.6
Temporary Boiler	0.04	0.15	0.06	0.20	3.59	12.59	3.65	12.77	0.53	1.86
P3-1	3.12	13.7	0.29	1.26	1.22	5.3	5.2	22.8	0.11	0.47
P3-2	0.1	0.4	0.01	0.06	0.03	0.1	0.13	0.6	0.0	0.01
P3-3	0.01	0.0	0	0	0	0	0	0	0	0
P4-1	3.12	13.7	0.29	1.26	1.22	5.3	5.2	22.8	0.11	0.47
P4-2	0.1	0.4	0.01	0.06	0.03	0.1	0.13	0.6	0.0	0.01
P4-3	0.01	0.0	0	0	0	0	0	0	0	0
P5-1	0.02	0.0	0	0	0	0	0	0	0	0
P5-2	0.02	0.0	0	0	0	0	0	0	0	0
P8-1N	0.15	0.7	0.04	0.18	0	0	0	0	0	0
P8-1S	0.15	0.7	0.04	0.18	0	0	0	0	0	0
P8-1A	0.03	0.1	0	0	0	0	0	0	0	0
P8-2N	0.15	0.7	0.04	0.18	0	0	0	0	0	0
P8-2S	0.15	0.7	0.04	0.18	0	0	0	0	0	0
P8-2A	0.03	0.1	0	0	0	0	0	0	0	0
P8-VE	0.07	0.3	0	0	0	0	0	0	0	0
P8-VW	0.07	0.3	0	0	0	0	0	0	0	0
P9-1	1.65	7.23	0.17	0.73	0	0	0	0	0	0
P10-1	1.65	7.23	0.17	0.73	0	0	0	0	0	0
P11-1	1.65	7.23	0.17	0.73	0	0	0	0	0	0
PKG-1	0.0	0.0	0	0	0	0	0	0	0	0
PKG-2	0.1	0.4	0	0	0	0	0	0	0	0
MT-2	0.07	0	0	0	0	0	0	0	0	0
MT-3	0.02	0.1	0	0	0	0	0	0	0	0
Heaters	0.44	1.0	0.14	0.31	5.83	12.8	4.9	10.7	0.32	0.7
Post Project Totals	**13.47**	**57.54**	**1.60**	**6.80**	**22.08**	**80.59**	**30.47**	**99.00**	**2.35**	**9.12**

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.
c) CO emissions have a facility-wide emission limit of 99 T/yr. CO emission tracking is required on a monthly and 12-consecutive month period.

Change in Potential to Emit

The change in facility-wide potential to emit is used to determine if a public comment period may be required and to determine the processing fee per IDAPA 58.01.01.225. The following table presents the facility-wide change in the potential to emit for criteria pollutants.

Table 6 CHANGES IN POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$		SO_2		NO_X		CO		VOC	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Pre-Project Potential to Emit	16.06	69.09	2.04	8.79	29.45	116.05	46.33	193.60	2.9	12.0
Post Project Potential to Emit	13.47	57.54	1.60	6.80	22.08	80.59	30.47	99.00	2.35	9.12
Changes in Potential to Emit	**-2.59**	**-11.55**	**-0.44**	**-1.99**	**-7.37**	**-35.46**	**-15.86**	**-94.60**	**-0.55**	**-2.88**

Non-Carcinogenic TAP Emissions

A summary of the estimated PTE for non-carcinogenic toxic air pollutants (TAP) emissions is not listed because the project resulted in an over-all significant decrease in all emissions.

Carcinogenic TAP Emissions

A summary of the estimated PTE for carcinogenic toxic air pollutants (TAP) emissions is not listed because the project resulted in an over-all significant decrease in all emissions.

Post Project HAP Emissions

A summary of the estimated PTE for HAP emissions is not listed because the project resulted in an over-all significant decrease in all emissions. The facility was major for NO_X and CO in the most recent Tier I Operating Permit T1-2019.0018 issued June 20, 2019. In this Tier I Operating permit the facility is not major for HAPs.

Ambient Air Quality Impact Analyses

The submitted information and analyses showed either a) that estimated potential/allowable emissions are at a level defined as below regulatory concern (BRC) and do not require a NAAQS compliance demonstration; b) that predicted pollutant concentrations from emissions associated with the project as modeled were below Significant Impact Levels (SILs) or other applicable regulatory thresholds; or c) that predicted pollutant concentrations from emissions associated with the project, when appropriately combined with co-contributing sources and background concentrations, were below applicable NAAQS at ambient air locations where and when the project has a significant impact. The application also showed that TAP emission increases associated with the project will not result in increased ambient air impacts exceeding allowable TAP increments.

The information and analyses submitted with the PTC application, combined with DEQ's review of those analyses, demonstrated to DEQ's satisfaction that emissions from the BAF Shelly Facility Temporary Boiler Project will not cause or significantly contribute to a violation of any applicable ambient air quality standard or TAP increment.

The applicant has demonstrated pre-construction compliance to DEQ's satisfaction that emissions from this facility will not cause or significantly contribute to a violation of any ambient air quality standard. The applicant has also demonstrated pre-construction compliance to DEQ's satisfaction that the emissions increase due to this permitting action will not exceed any acceptable ambient concentration (AAC) or acceptable ambient concentration for carcinogens (AACC) for toxic air pollutants (TAP). A summary of the Ambient Air Impact Analysis for TAP is provided in Appendix A.

An ambient air quality impact analyses document has been crafted by DEQ based on a review of the modeling analysis submitted in the application. That document is part of the final permit package for this permitting action (see

Appendix B – POINT STACK RELEASE PARAMETERS

TABLE 2

POINT SOURCE STACK RELEASE PARAMETERS

Stack Identification	Source ID	Stack Release Type	Easting (X), m	Northing (Y), m	Base Elevation, m	Stack Height, ft	Temperature, °F	Exit Velocity, fps	Stack Diameter, ft
Boiler 1	BLR1	DEFAULT	408776.3	4802871.0	1409.1	33.7	390.0	40.74	2.50
Boiler 3	BLR3	DEFAULT	408790.3	4802871.0	1409.4	33.3	320.0	25.46	2.50
Boiler 4	BLR4	DEFAULT	408776.9	4802806.7	1409.1	38.5	360.0	29.18	4.00
Boiler 5	BLR5	DEFAULT	408852.5	4802690.0	1411.2	42.2	300.0	43.88	2.00
P3-1	P3_1	DEFAULT	408808.3	4802839.3	1408.9	66.5	163.0	55.85	4.47
P3-2	P3_2	DEFAULT	408804.0	4802845.7	1409.1	26.8	94.0	48.27	1.22
P3-3	P3_3	DEFAULT	408802.2	4802841.2	1408.9	34.1	97.0	26.78	1.36
P4-1	P4_1	DEFAULT	408808.3	4802832.6	1408.9	66.5	163.0	55.85	4.47
P4-2	P4_2	DEFAULT	408805.3	4802829.9	1409.0	27.3	102.0	44.80	1.26
P4-3	P4_3	DEFAULT	408801.3	4802830.5	1408.9	28.4	112.0	23.27	1.46
P5-1	P5_1	DEFAULT	408801.6	4802866.5	1409.4	24.4	85.0	51.57	0.33
P5-2	P5_2	DEFAULT	408801.0	4802858.2	1409.4	27.4	85.0	51.57	0.33
P6-1	P6_1	DEFAULT	408695.7	4802839.6	1408.6	50.8	127.0	48.79	3.50
P6-2	P6_2	DEFAULT	408720.1	4802844.8	1408.8	50.8	100.0	51.04	2.50
P8-1N	P8_1N	DEFAULT	408755.6	4802902.7	1409.4	35.4	112.0	37.80	2.00
P8-1S	P8_1S	DEFAULT	408755.6	4802900.6	1409.4	36.7	112.0	44.28	2.00
P8-1A	P8_1A	DEFAULT	408757.1	4802898.2	1409.3	35.1	90.0	52.53	0.83
P8-2N	P8_2N	DEFAULT	408751.3	4802902.7	1409.4	30.3	112.0	37.80	2.00
P8-2S	P8_2S	DEFAULT	408751.3	4802900.6	1409.4	30.7	112.0	44.28	2.00
P8-2A	P8_2A	DEFAULT	408749.8	4802897.5	1409.4	35.2	90.0	52.53	0.83
P8-VE	P8_VE	DEFAULT	408757.7	4802897.8	1409.3	33.2	85.0	50.93	0.50
P8-VW	P8_VW	DEFAULT	408757.7	4802899.4	1409.3	33.2	85.0	50.93	0.50
P9-1	P9_1	DEFAULT	408716.0	4802809.0	1408.8	59.0	102.0	41.65	4.00
P10-1	P10_1	DEFAULT	408708.0	4802809.0	1408.8	59.0	102.0	41.65	4.00
P11-1	P11_1	DEFAULT	408701.0	4802809.0	1408.8	59.0	102.0	41.65	4.00
Pkg-1	PKG_1	DEFAULT	408796.4	4802883.2	1409.4	31.1	80.0	49.96	0.99
Pkg-2	PKG_2	DEFAULT	408763.8	4802890.8	1409.1	31.1	80.0	43.85	0.83
MT-2	MT_2	DEFAULT	408770.5	4802817.1	1409.1	33.7	80.0	50.13	0.67
MT-3	MT_3	DEFAULT	408804.3	4802868.6	1409.4	50.1	80.0	51.57	0.33

Appendix C).

REGULATORY ANALYSIS

Attainment Designation (40 CFR 81.313)

The facility is located in Bingham County, which is designated as attainment or unclassifiable for $PM_{2.5}$, PM_{10}, SO_2, NO_2, CO, and Ozone. Refer to 40 CFR 81.313 for additional information.

Facility Classification

The AIRS/AFS facility classification codes are as follows:

For HAPs (Hazardous Air Pollutants) Only:

A = Use when any one HAP has permitted emissions > 10 T/yr or if the aggregate of all HAPS (Total HAPs) has permitted emissions > 25 T/yr.

SM80 = Use if a synthetic minor (uncontrolled HAPs emissions are > 10 T/yr or if the aggregate of all uncontrolled HAPs (Total HAPs) emissions are > 25 T/yr and permitted emissions fall below applicable major source thresholds) and the permit sets limits > 8 T/yr of a single HAP or ≥ 20 T/yr of Total HAPs.

SM = Use if a synthetic minor (uncontrolled HAPs emissions are > 10 T/yr or if the aggregate of all uncontrolled HAPs (Total HAPs) emissions are > 25 T/yr and permitted emissions fall below applicable major source thresholds) and the permit sets limits < 8 T/yr of a single HAP and/or < 20 T/yr of Total HAPs.

B = Use when the potential to emit (i.e. uncontrolled emissions and permitted emissions) are below the 10 and 25 T/yr HAP major source thresholds.

UNK = Class is unknown.

For All Other Pollutants:

A = Use when permitted emissions of a pollutant are > 100 T/yr.

SM80 = Use if a synthetic minor for the applicable pollutant (uncontrolled emissions are > 100 T/yr and permitted emissions fall below 100 T/yr) and permitted emissions of the pollutant are ≥ 80 T/yr.

SM = Use if a synthetic minor for the applicable pollutant (uncontrolled emissions are > 100 T/yr and permitted emissions fall below 100 T/yr) and permitted emissions of the pollutant are < 80 T/yr.

B = Use when the potential to emit (i.e. uncontrolled emissions and permitted emissions) are below the 100 T/yr major source threshold.

UNK = Class is unknown.

Table 7 REGULATED AIR POLLUTANT FACILITY CLASSIFICATION

Pollutant	Uncontrolled PTE (T/yr)	Permitted PTE (T/yr)	Major Source Thresholds (T/yr)	AIRS/AFS Classification
PM	57.7	57.54	**100**	B
PM_{10}	57.7	57.54	**100**	B
$PM_{2.5}$	57.7	57.54	**100**	B
SO_2	6.01	6.80	**100**	B
NO_X	99.3	80.59	**100**	B
CO	112.6	99.00	**100**	SM80
VOC	5.7	9.12	**100**	B
HAP (single)	0.76	<10	**10**	B
Total HAPs	0.80	<25	**25**	B

Permit to Construct (IDAPA 58.01.01.201)

IDAPA 58.01.01.201..... Permit to Construct Required

The permittee has requested that a PTC be issued to the facility for the proposed new emissions source. Therefore, a permit to construct is required to be issued in accordance with IDAPA 58.01.01.220. This permitting action was processed in accordance with the procedures of IDAPA 58.01.01.200-228.

Tier II Operating Permit (IDAPA 58.01.01.401)

IDAPA 58.01.01.401..... Tier II Operating Permit

The application was submitted for a permit to construct (refer to the Permit to Construct section), and an optional Tier II operating permit has not been requested. Therefore, the procedures of IDAPA 58.01.01.400–410 were not applicable to this permitting action.

Visible Emissions (IDAPA 58.01.01.625)

IDAPA 58.01.01.625..... Visible Emissions

The sources of PM emissions at this facility are subject to the State of Idaho visible emissions standard of 20% opacity. This requirement is assured by Permit Conditions 2.7, 2.8, and 2.9.

Standards for New Sources (IDAPA 58.01.01.676)

IDAPA 58.01.01.676..... Standards for New Sources

The fuel burning equipment located at this facility, with a maximum rated input of ten (10) million BTU per hour or more, are subject to a particulate matter limitation of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume when combusting gaseous fuels. Fuel-Burning Equipment is defined as any furnace, boiler, apparatus, stack and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer. This requirement is assured by Permit Condition 2.15.

Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

IDAPA 58.01.01.301..... Requirement to Obtain Tier I Operating Permit

Post project facility-wide emissions from this facility do not have a potential to emit greater than 100 tons per year for PM_{10}, SO_2, NO_X, CO, VOC, and HAP) or 10 tons per year for any one HAP or 25 tons per year for all HAP combined as demonstrated previously in the Emissions Inventories Section of this analysis. Therefore, the facility is not a Tier I source in accordance with IDAPA 58.01.01.006 and the requirements of IDAPA 58.01.01.301 do not apply.

PSD Classification (40 CFR 52.21)

40 CFR 52.21 ..... Prevention of Significant Deterioration of Air Quality

The facility is not a major stationary source as defined in 40 CFR 52.21(b)(1), nor is it undergoing any physical change at a stationary source not otherwise qualifying under paragraph 40 CFR 52.21(b)(1) as a major stationary source, that would constitute a major stationary source by itself as defined in 40 CFR 52. Therefore in accordance with 40 CFR 52.21(a)(2), PSD requirements are not applicable to this permitting action. The facility is not a designated facility as defined in 40 CFR 52.21(b)(1)(i)(a), and does not have facility-wide emissions of any criteria pollutant that exceed 250 T/yr.

NSPS Applicability (40 CFR 60)

Because the project involves permitting four boilers rated at greater than 10 MMBtu/hr (but less than 100 MMBtu/hr) the following NSPS requirement may apply to this facility:

40 CFR 60, Subpart Dc	Standards of Performance for Small Industrial–Commercial–Institutional Steam Generating Units

Boiler 4 is a 72 MMBtu/hr natural gas fired boiler and was installed in 1989, but the application does not identify the exact date of construction, that is, before or after the NSPS applicability date of June 9, 1989. BAF submitted an addendum to the application dated October 8, 2008, which identified Subpart Dc as being applicable to Boiler 4 at the facility, so it is assumed boiler 4 was installed after June 9, 1989. The temporary boiler is 98.6 MMBtu/hr and was installed in 2017. The temporary boiler does not meet the exemption criteria, therefore it is subject to this subpart.

§ 60.40c	Applicability and Delegation of Authority

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in
§60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under §60.14.

(e) Affected facilities (i.e. heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NOX standards under this subpart and the SO2 standards under subpart J or subpart Ja of this part, as applicable.

(i) Temporary boilers are not subject to this subpart.

The Temporary Boiler does not meet this exemption criterion. Therefore, the Temporary Boiler is subject to this subpart. Boiler 4 is also subject to this subpart.

§60.41c Definitions

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (i.e., the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see §60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see §60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means:
(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or
(2) Liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or
(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:
(1) The equipment is attached to a foundation.
(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.
(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.
(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

The Temporary Boiler does not meet this definition of temporary boiler.

Wet flue gas desulfurization technology means an SO2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

§60.42c Standard for sulfur dioxide (SO2).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither:
cause to be discharged into the atmosphere from the affected facility any gases that contain SO2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO2 in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.
(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that:
(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:
(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO2 emission rate (80 percent reduction); nor
(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO2 in excess of SO2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject

to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO2 emissions limit or the 90 percent SO2 reduction equirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.
(2) Combusts only coal and that uses an emerging technology for the control of SO2 emissions shall neither:
(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO2 in excess of 50 percent (0.50) of the potential SO2 emission rate (50 percent reduction); nor
(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO2 in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO2 reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO2 in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).
(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;
(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.
(3) Affected facilities located in a noncontinental area; or
(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO2 in excess of the following:
(1) The percent of potential SO2 emission rate or numerical SO2 emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that
(i) Combusts coal in combination with any other fuel;
(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and
(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and
(2) The emission limit determined according to the following formula for any affected facility
that combusts coal, oil, or coal and oil with any other fuel:
Where:
Es = SO2 emission limit, expressed in ng/J or lb/MMBtu heat input;
Ka = 520 ng/J (1.2 lb/MMBtu);
Kb = 260 ng/J (0.60 lb/MMBtu);
Kc = 215 ng/J (0.50 lb/MMBtu);
Ha = Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];
Hb = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

Hc = Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential SO2 emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:
(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO2 emission rate; and
(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO2 control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), as applicable.
(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).
(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).
(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).
(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(i) The SO2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

Boiler 4 and the Temporary Boiler will not combust any of the fuel types that are described in 60.42c.

§60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:
(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.
(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:
(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or
(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.
(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:
(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and
(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.
(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.
(4) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under §60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO2 emissions is not subject to the PM limit in this section.

Boiler 4 and the Temporary Boiler will not combust any of the fuel types that are described in 60.43c.

§60.44c	Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and §60.8(b), performance tests required under §60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO2 emission limits under §60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load

during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and §60.8, compliance with the percent reduction requirements and SO2 emission limits under §60.42c is based on the average percent reduction and the average SO2 emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO2 emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO2 emission rate (Eho) and the 30-day average SO2 emission rate (Eao). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate Eao when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:
(1) An adjusted Eho (Ehoo) is used in Equation 19-19 of Method 19 of appendix A of this part to compute the adjusted Eao (Eaoo). The Ehoo is computed using the following formula:
Where:
Ehoo = Adjusted Eho, ng/J (lb/MMBtu);
Eho = Hourly SO2 emission rate, ng/J (lb/MMBtu);
Ew = SO2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value Ew for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure Ew if the owner or operator elects to assume Ew = 0.
Xk = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.
(2) The owner or operator of an affected facility that qualifies under the provisions of §60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters Ew or Xk if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b) shall determine compliance with the SO2 emission limits under §60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:
(1) If only coal is combusted, the percent of potential SO2 emission rate is computed using the following formula:
Where:
%Ps = Potential SO2 emission rate, in percent;
%Rg = SO2 removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and
%Rf = SO2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.
(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:
(i) To compute the %Ps, an adjusted %Rg (%Rgo) is computed from Eaoo from paragraph (e)(1) of this section and an adjusted average SO2 inlet rate (Eaio) using the following formula:
Where:
%Rgo = Adjusted %Rg, in percent;
Eaoo = Adjusted Eao, ng/J (lb/MMBtu); and
Eaio = Adjusted average SO2 inlet rate, ng/J (lb/MMBtu).
(ii) To compute Eaio, an adjusted hourly SO2 inlet rate (Ehio) is used. The Ehio is computed using the following formula:
Where:
Ehio = Adjusted Ehi, ng/J (lb/MMBtu);
Ehi = Hourly SO2 inlet rate, ng/J (lb/MMBtu);

Ew = SO2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value Ew for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure Ew if the owner or operator elects to assume Ew = 0; and Xk = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under §60.46c(d)(2).

(h) For affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in §60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO2 standards under §60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO2 emissions data in calculating %Ps and Eho under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under §60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating %Ps or Eho pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

Because Boiler 4 and the Temporary Boiler is not subject to the SO2 performance standards of 60.42c, the compliance and performance test methods of 60.44c are not applicable.

§60.45c	Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under §60.43c shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.
(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.
(2) Method 3A or 3B of appendix A-2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A-3 of this part or 17 of appendix A-6 of this part.
(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:
(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.
(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.
(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.
(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F).
(6) For determination of PM emissions, an oxygen (O2) or carbon dioxide (CO2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.
(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J lb/MMBtu) heat input shall be determined using:
(i) The O2 or CO2 measurements and PM measurements obtained under this section,
(ii) The dry basis F factor, and
(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.
(8) Method 9 of appendix A-4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under §60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) In place of PM testing with Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.
(1) Notify the Administrator 1 month before starting use of the system.
(2) Notify the Administrator 1 month before stopping use of the system.
(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.
(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.
(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.
(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.
(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.
(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.
(ii) [Reserved]
(8) The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.
(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (c)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.
(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O2 (or CO2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.
(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and
(ii) For O2 (or CO2), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.
(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.
(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.
(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in §60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (i.e., reference method) data and performance test (i.e., compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/ert tool.html/) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under §60.43c(e)(4) shall follow the applicable procedures under §60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

Because Boiler 4 and the Temporary Boiler is not subject to the PM performance standards of 60.43c, the compliance and performance test methods of 60.45c are not applicable.

§60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO2 emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO2 concentrations and either O2 or CO2 concentrations at the outlet of the SO2 control device (or the outlet of the steam generating unit if no SO2 control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under §60.42c shall measure SO2 concentrations and either O2 or CO2 concentrations at both the inlet and outlet of the SO2 control device.

(b) The 1-hour average SO2 emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average SO2 emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under §60.13(h)(2). Hourly SO2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.
(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.
(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.
(3) For affected facilities subject to the percent reduction requirements under §60.42c, the span value of the SO2 CEMS at the inlet to the SO2 control device shall be 125 percent of the maximum estimated hourly potential SO2 emission rate of the fuel combusted, and the span value of the SO2 CEMS at the outlet from the SO2 control device shall be 50 percent of the maximum estimated hourly potential SO2 emission rate of the fuel combusted.
(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, the span value of the SO2 CEMS at the outlet from the SO2 control device (or outlet of the steam generating unit if no SO2 control

device is used) shall be 125 percent of the maximum estimated hourly potential SO2 emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO2 control device (or outlet of the steam generating unit if no SO2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO2 emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO2 control device (or outlet of the steam generating unit if no SO2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO2 emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.
(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO2 input rate.
(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.
(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO2 at the inlet or outlet of the SO2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO2 and CO2 measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO2 standards based on fuel supplier certification, as described under §60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

§60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under §60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in §60.43c(c) that is not required to use a COMS due to paragraphs (c), (d),

(e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (i.e. , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (i.e., 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (i.e., 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in §60.45c(a)(8).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO2 or PM emissions and that are subject to an opacity standard in §60.43c(c) are not required to operate a COMS if they follow the applicable procedures in §60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in 60.45c(c). The CEMS specified in paragraph §60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or
(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.
(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in 60.58b(i)(3) of subpart Eb of this part.
(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).
(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).
(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.
(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.
(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.
(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) An owner or operator of an affected facility that is subject to an opacity standard in §60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.
(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section §60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section §60.48Da of this part.
(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under §60.48c(c).

Because Boiler 4 and the Temporary Boiler are not subject to the SO2 performance standards of 60.42c, the emission monitoring provisions for sulfur dioxide of 60.46c are not applicable.

§60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:
(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.
(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.
(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

Because the Blackfoot Facility is an affected facility under this subpart, notification is required in accordance with 60.48(c)(a).

(4) Notification if an emerging technology will be used for controlling SO2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO2 emission limits of §60.42c, or the PM or opacity limits of §60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in §60.7, the owner or operator of an affected facility subject to the opacity limits in §60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.
(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(1)(i) through (iii) of this section.
(i) Dates and time intervals of all opacity observation periods;
(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and
(iii) Copies of all visible emission observer opacity field data sheets;
(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs
(c)(2)(i) through (iv) of this section.
(i) Dates and time intervals of all visible emissions observation periods;
(ii) Name and affiliation for each visible emission observer participating in the performance test;
(iii) Copies of all visible emission observer opacity field data sheets; and
(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

(d) The owner or operator of each affected facility subject to the SO2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.
(1) Calendar dates covered in the reporting period.
(2) Each 30-day average SO2 emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.
(3) Each 30-day average percent of potential SO2 emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.
(4) Identification of any steam generating unit operating days for which SO2 or diluent (O2 or CO2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.
(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.
(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.
(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.
(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.
(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.
(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.
(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:
(1) For distillate oil:
(i) The name of the oil supplier;
(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c; and
(iii) The sulfur content or maximum sulfur content of the oil.
(2) For residual oil:
(i) The name of the oil supplier;
(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;
(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself);
and
(iv) The method used to determine the sulfur content of the oil.
(3) For coal:
(i) The name of the coal supplier;
(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another

location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);
(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and
(iv) The methods used to determine the properties of the coal.
(4) For other fuels:
(i) The name of the supplier of the fuel;
(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and
(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

Boiler 4 and the Temporary Boiler are subject to this recordkeeping requirement. EPA has also made a determination that for boilers that are gas-fired only, monthly fuel use records are adequate. (See EPA Applicability Determination Index – Control Number 0600056.)

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.
(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

NESHAP Applicability (40 CFR 61)

The project is not subject to any NESHAP requirements in 40 CFR 61.

GACT Applicability (40 CFR 63)

The project is not subject to any GACT standards in 40 CFR Part 63, specifically its boilers under Subpart DDDDD and JJJJJJ, as the facility has gas-fired boilers, and is not located at, or part of, a major source of HAP.

Permit Conditions Review

This section describes the permit conditions for this modified permit or only those permit conditions that have been added, revised, modified or deleted as a result of this permitting action. The General Provisions from the current template have been incorporated into this permitting action.

Existing Permit Condition 1.1

Describes the scope of this permitting project. The facility has removed boilers 1, 3, and 5. The facility has also removed P6-1 and P6-2 from the process lines. The classification of the facility is changing to SM80 due to the incorporation of CO tracking requirements and an emission limit of 99 T/yr in CO.

Existing Permit Condition 1.2

Explains how to identify the revised, added, and modified permit conditions.

Existing Permit Condition 1.3

Lists the regulated sources.

Section 2 in the Permit was taken directly from the Existing Tier I Operating Permit and put into this PTC, because upon issuance of this PTC the Tier I Operating permit will be terminated.

Newly Added Permit Condition 2.1

Establishes facility-wide CO tons per year emission limit to maintain the facility classification of SM80 and terminate the current Tier I Operating permit.

Newly Added Permit Condition 2.2

Requires the permittee to remove or render inoperable boilers 1, 3, 5, and the P6-1 dryer, such that these emission units no longer have the potential to emit a regulated air pollutant. Reclassification from a major facility to a synthetic minor facility, no longer requiring the facility to hold a Tier One operating permit is based on this requirement and Facility-Wide CO Emission Limit permit condition.

Newly Added Permit Condition 2.3

Establishes the monitoring and recordkeeping to demonstrate compliance with the facility-wide CO annual emission limit permit condition.

Newly Added Permit Condition 2.4

Establishes the notification requirements to demonstrate compliance with Boilers 1, 3, 5, and P6-1 Dryer Removal or Render Inoperable Requirement permit condition.

Existing Permit Condition 3.1

Is a revised process description of the facility after the removal of boilers 1, 3, and 5, as well as the removal of P6-1 and P6-2, and the installation of the temporary boiler.

Existing Permit Condition 3.2

This permit condition was revised to reflect the removal of boilers 1, 3, and 5, and the installation of the temporary boiler.

Existing Permit Condition 3.3

Was revised to reflect the current emissions after the removal of boilers 1, 3, and 5, and the installation of the temporary boiler.

Newly Added Permit Condition 3.4

Establishes the opacity limit permit condition for the boiler stacks.

Newly Added Permit Condition 3.7

Establishes that only one boiler shall operate at a single time. The emissions and the modeling was analyzed with only one boiler operating at a single time.

Newly Added Permit Condition 3.10

Establishes the monitoring and recordkeeping requirements to demonstrate compliance with the Boiler 4 and Temporary Boiler Operations permit condition. This permit condition will allow the permit to show that only one boiler operates at a single time.

Existing Permit Condition 5.2

This permit condition was revised to reflect the removal of P6-1 and P6-2 from Process Line B.

Existing Permit Condition 5.3

This permit condition was revised to reflect the removal of P6-1and P6-2 from Process Line B.

PUBLIC REVIEW

Public Comment Opportunity

Because this permitting action does not authorize an increase in emissions, an opportunity for public comment period was not required or provided in accordance with IDAPA 58.01.01.209.04 or IDAPA 58.01.01.404.04.

APPENDIX A – EMISSIONS INVENTORIES

Table D1
Emission Calculation

Parameter	Value	Units
natural gas heat content	1020	BTU/scf
Fd, dry F-factor for NG combustion	8,710	dscf/MMBtu
Fw, wet F-factor for NG combustion	10,610	wscf/MMBtu
atmospheric oxygen	20.9%	-
barometric pressure at 4600' MSL	0.85	atm
Formula Weights		
NOx	46	-
CO	28	
Temporary Boiler Data		
Max firing rate	98.6	MMBtuh
Steam rate	67,050	pph
NOx emissions	30	ppmvd @ 3% oxygen
CO emissions	50	ppmvd @ 3% oxygen
SO2 emissions	0.60	lb/MMscf
PM emisisons	0.43	lb/MMscf
VOC emissions	5.50	lb/MMscf
Pb emissions	5.0E-04	lb/MMscf
Flue gas temperature	550	°F
excess air	15%	-
stack diameter	4.00	ft
Days of operation in 2020	292	days

Boiler 4		
Steam rate	60,000.0	pph

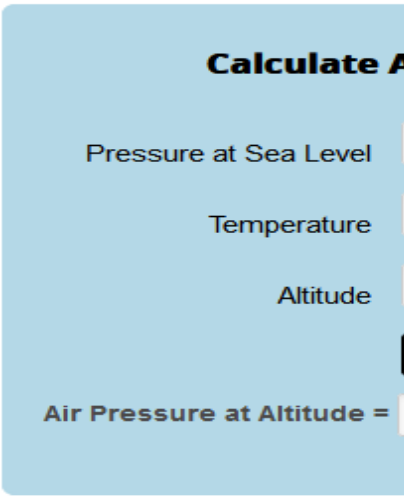
l

Input Values

Basis
From Table 19-2, EPA Test Method 19
From Table 19-2, EPA Test Method 19
Mide Engineering air pressure calculator, https://www.mide.com/air-pressure-at-altitude-calculator
as NO2
manufacturer data
manufacturer data
NXT-109 burner data sheet, with FGR
NXT-109 burner data sheet
AP-42, Table 1.4-2.
"NG_process_gas_LPG_PM_factors" spreadsheet, prepared by Roy Huntley, EPA. https://www.epa.gov/sites/production/files/2015-08/natgas_procgas_lpg_pm_efs_not_ap42_032012_revisions.xls
AP-42, Table 1.4-2.
AP-42, Table 1.4-2.
NXT Burner performance data sheet
NXT Burner performance data sheet
field measurement
Based on operation starting 3/14/2020

Tier I permit

https://www.mide.com/air-pres



31-Dec

ssure-at-altitude-calculator

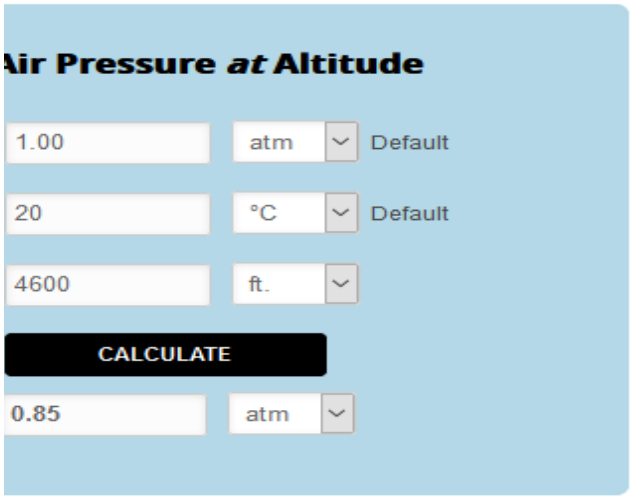


Table 1
Criteria Pollutant Emission Factors fo

Parameter	Value	Units
Calculation Constants		
Boiler Heat Rate	98.6	MMBtuh
dry F-factor for NG combustion, 3% O2	10,170	dscf @3% O2/MMBtu
Temp Boiler NOx emission factor		
emission factor, ppmvd @ 3% O2	30	ppmvd @ 3% O2
emission factor, lb/MMdscf @ 3% O3	3.583	lb/MMdscf @ 3% O2
emission factor, heat basis	0.03644	lb/MMBtu
emission factor, fuel rate	37.17	lb/MMscf NG
Temporary Boiler SO2 emission factor		
fuel rate emission factor	0.600	lb/MMscf
heat rate emission factor	5.88E-04	lb/MMBtu
Temporary Boiler CO emission factor		
emission factor, ppmvd @ 3% O2	50	ppmvd @ 3% O2
emission factor, lb/MMdscf @ 3% O3	3.635	lb/MMdscf @ 3% O2
emission factor, heat basis	0.03697	lb/MMBtu
emission factor, fuel rate	37.71	lb/MMscf NG
Temporary Boiler PM emission factor		
fuel rate emission factor	*0.43*	*lb/MMscf*
heat rate emission factor	4.22E-04	lb/MMBtu
Temporary Boiler VOC emission factor		
fuel rate emission factor	5.50	lb/MMscf
heat rate emission factor	5.39E-03	lb/MMBtu
Temporary Boiler Pb emission factor		
fuel rate emission factor	5.00E-04	lb/MMscf
heat rate emission factor	4.90E-07	lb/MMBtu

or Temp Boiler

Basis
calculated from fuel rate and HHV NG
=Fd*(20.9/(20.9-3))
Vendor statement
AP-42, Table 1.4-2.
Based on HHV = 1020 Btu/scf
Vendor statement
Revisions to PM emission factors presented in "NG_process_gas_LPG_PM_factors" spreadsheet, prepared by Roy Huntley, EPA. https://www.epa.gov/sites/production/files/2015-08/natgas_procgas_lpg_pm_efs_not_ap42_032012_revi
lb/MMscf ÷ HHV NG
AP-42, Table 1.4-2.
lb/MMscf ÷ HHV NG
AP-42, Table 1.4-2.
lb/MMscf ÷ HHV NG

Table 2
Criteria Air Pollutant Emissions for Temporary Boiler

Pollutant	Emission Factor, lb/MMBtu	Emission Rate*	
		lb/hr	ton/yr
CO	0.037	3.65	12.77
NOx	0.036	3.59	12.59
SO2 + SO3	0.00059	0.06	0.20
PM10	0.0004	0.04	0.15
Direct PM2.5	0.000	0.04	0.15
VOC	0.005	0.53	1.86
Pb	4.9E-07	0.00005	0.0002

* Based on 99 MMBtu/h max fuel rate and 292 days of operation during 2020.

Table 3
Toxic and Hazardous Air Pollutant Emission Factors - NG Combustion

Air Pollutant	lb/MMBTU	Emission Factor Reference	CAA Hazardous Air Pollutant?	ID TAP (C, NC, or No)?
POM Components				
Acenaphthene	1.76E-09	AP-42, Table 1.4-3	Yes	C (General PAH)
Acenaphthylene	1.76E-09	AP-42, Table 1.4-3	Yes	C (General PAH)
Anthracene	2.35E-09	AP-42, Table 1.4-3	Yes	C (General PAH)
Benz(a)anthracene	1.76E-09	AP-42, Table 1.4-3	Yes	C (7-PAH Group)
Benzo(a)pyrene	1.18E-09	AP-42, Table 1.4-3	Yes	C (7-PAH Group)
Benzo(b)fluoranthene	1.76E-09	AP-42, Table 1.4-3	Yes	C (7-PAH Group)
Benzo(g,h,i)perylene	1.18E-09	AP-42, Table 1.4-3	Yes	C (General PAH)
Benzo(k)fluoroanthene	1.76E-09	AP-42, Table 1.4-3	Yes	C (7-PAH Group)
Chrysene	1.76E-09	AP-42, Table 1.4-3	Yes	C (7-PAH Group)
Dibenzo(a,h)anthracene	1.18E-09	AP-42, Table 1.4-3	Yes	C (7-PAH Group)
7,12-Dimethylbenz(a)anthracene	1.57E-08	AP-42, Table 1.4-3	Yes	C (General PAH)
Fluoranthene	2.94E-09	AP-42, Table 1.4-3	Yes	C (General PAH)
Fluorene	2.75E-09	AP-42, Table 1.4-3	Yes	C (General PAH)
Indeno(1,2,3-cd)pyrene	1.76E-09	AP-42, Table 1.4-3	Yes	C (7-PAH Group)
2-Methylnaphthalene	2.35E-08	AP-42, Table 1.4-3	Yes	C (General PAH)
3-Methylchloroanthene	1.76E-09	AP-42, Table 1.4-3	Yes	C (General PAH)
Naphthalene	5.98E-07	AP-42, Table 1.4-3	Yes	C (General PAH)
Phenanthrene	1.67E-08	AP-42, Table 1.4-3	Yes	C (General PAH)
Pyrene	4.90E-09	AP-42, Table 1.4-3	Yes	C (General PAH)
PAH (Idaho)	*6.73E-07*	*Summation of individual ID PAH components*	*Yes (EPA POM component)*	*C*
POM (Idaho)	*1.12E-08*	*Summation of ID POM 7-PAH components*	*Yes (EPA POM component)*	*C*
POM (EPA)	*6.85E-07*	*Sum of individual POM componnents*	*Yes*	-
Benzene	2.06E-06	AP-42, Table 1.4-3	Yes	C
Dichlorobenzene	1.18E-06	AP-42, Table 1.4-3	Yes	NC
Formaldehyde	7.35E-05	AP-42, Table 1.4-3	Yes	C
Hexane	1.76E-03	AP-42, Table 1.4-3	Yes	NC
Pentane	2.55E-03	AP-42, Table 1.4-3	No	NC
Toluene	3.33E-06	AP-42, Table 1.4-3	Yes	NC
Arsenic	1.96E-07	AP-42, Table 1.4-4	Yes	C
Beryllium	1.18E-08	AP-42, Table 1.4-4	Yes	C
Cadmium	1.08E-06	AP-42, Table 1.4-4	Yes	C
Chromium	1.37E-06	AP-42, Table 1.4-4	Yes	NC
Chromium (VI)	6.86E-08	AP-42, Table 1.4-4	Yes (included in chromium)	C
Cobalt	8.24E-08	AP-42, Table 1.4-4	Yes	NC
Manganese	3.73E-07	AP-42, Table 1.4-4	Yes	NC
Mercury	2.55E-07	AP-42, Table 1.4-4	Yes	No
Nickel	2.06E-06	AP-42, Table 1.4-4	Yes	C
Selenium	2.35E-08	AP-42, Table 1.4-4	Yes	NC
Nitrous Oxide	2.16E-03	AP-42, Table 1.4-2	No	NC
EPA Total HAPs	1.85E-03	Summation of individual EPA HAP components	Yes	No
Largest Individual HAP	1.76E-03	Hexane	Yes	Yes

Based on 1020 BTU/scf natural gas heat content

Table 4
Temporary Boiier Toxic Air Pollutant Emissions

Air Pollutant	Idaho TAP Category	EPA Hazardous Air Pollutant?	Emission Factor, lb/MMBtu	Emission Rate, lb/hr*	SEL, lb/hr	% of SEL
PAH (Idaho)	C	Yes (EPA POM component)	6.73E-07	6.64E-05	NA†	-
POM (Idaho)	C	Yes (EPA POM component)	1.12E-08	1.10E-06	NA†	-
Benzene	C	Yes	2.06E-06	2.03E-04	NA†	-
Dichlorobenzene	NC	Yes	1.18E-06	1.16E-04	NA†	-
Formaldehyde	C	Yes	7.35E-05	7.25E-03	NA†	-
Hexane	NC	Yes	1.76E-03	1.74E-01	NA†	-
Pentane	NC	No	2.55E-03	2.51E-01	1.18E+02	0.2%
Toluene	NC	Yes	3.33E-06	3.29E-04	NA†	-
Arsenic	C	Yes	1.96E-07	1.93E-05	NA†	-
Beryllium	C	Yes	1.18E-08	1.16E-06	NA†	-
Cadmium	C	Yes	1.08E-06	1.06E-04	NA†	-
Chromium	NC	Yes	1.37E-06	1.35E-04	NA†	-
Chromium (VI)	C	Yes (included in chromium)	6.86E-08	6.76E-06	NA†	-
Cobalt	NC	Yes	8.24E-08	8.12E-06	NA†	-
Manganese	NC	Yes	3.73E-07	3.68E-05	NA†	-
Mercury	No	Yes	2.55E-07	2.51E-05	NA†	-
Nickel	C	Yes	2.06E-06	2.03E-04	NA†	-
Selenium	NC	Yes	2.35E-08	2.32E-06	NA†	-
Nitrous Oxide	NC	No	2.16E-03	2.13E-01	6.00E+00	3.5%

* Based on NG firing rate = 91.5 MMBtuh

† TAP analysis not needed because ambient impacts of TAP addressed in 40 CFR 63, Subpart JJJJJJ.

Summary of Potential Emissions -
Shelley Facility of Basic American Foods

Boiler 4	0.55	2.4	0.13	0.74	10.16	44.4	11.26	49.2	1.28	5.6
Temporary Boiler	0.04	0.15	0.06	0.20	3.59	12.59	3.65	12.77	0.53	1.86
P3-1	3.12	13.7	0.29	1.3	1.22	5.3	5.20	22.8	0.11	0.5
P3-2	0.10	0.4	0.01	0.1	0.03	0.1	0.13	0.6	0.00	0.0
P3-3	0.01	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
P4-1	3.12	13.7	0.29	1.3	1.22	5.3	5.20	22.8	0.11	0.5
P4-2	0.10	0.4	0.01	0.1	0.03	0.1	0.13	0.6	0.00	0.0
P4-3	0.01	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
P5-1	0.02	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
P5-2	0.02	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
P8-1N	0.15	0.7	0.04	0.2	0.00	0.0	0.00	0.0	0.00	0.0
P8-1S	0.15	0.7	0.04	0.2	0.00	0.0	0.00	0.0	0.00	0.0
P8-1A	0.03	0.1	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
P8-2N	0.15	0.7	0.04	0.2	0.00	0.0	0.00	0.0	0.00	0.0
P8-2S	0.15	0.7	0.04	0.2	0.00	0.0	0.00	0.0	0.00	0.0
P8-2A	0.03	0.1	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
P8-VE	0.07	0.3	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
P8-VW	0.07	0.3	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
P9-1	1.65	7.2	0.17	0.7	0.00	0.0	0.00	0.0	0.00	0.0
P10-1	1.65	7.2	0.17	0.7	0.00	0.0	0.00	0.0	0.00	0.0
P11-1	1.65	7.2	0.17	0.7	0.00	0.0	0.00	0.0	0.00	0.0
PKG-1	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
PKG-2	0.10	0.4	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
MT-2	0.07	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
MT-3	0.02	0.1	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
Fugitive Emissions										
Heaters	0.44	1	0.14	***0.31***	5.83	12.8	4.9	10.7	0.32	0.7
PTE - Emission Unit Total	13.5	57.5	1.6	6.8	22.1	80.6	30.5	119.5	2.4	9.1
PTE - with Proposed Operating Limit*	13.43	57.4	1.54	6.6	18.49	68.0	26.82	106.7	1.82	7.3

Table 6
Pre-Project Potential to Emit

Emissions Unit	$PM_{10}/PM_{2.5}$		SO2		NOx		CO		VO
	lb/hr	T/hr	lb/hr	T/hr	lb/hr	T/hr	lb/hr	T/hr	lb/hr
Point Sources									
Boiler I	0.29	1.3	0.02	0.1	3.87	17.0	3.25	14.2	0.21
Boiler 3	0.22	1.0	0.02	0.1	2.83	12.4	2.38	10.4	0.16
Boiler 4	0.55	2.4	0.13	0.7	10.16	44.4	11.26	49.2	1.28
Boiler 5	0.17	0.8	0.06	0.3	1.76	7.7	3.55	15.6	0.49
P3-1	3.12	13.7	0.29	1.3	1.22	5.3	5.20	22.8	0.11
P3-2	0.10	0.4	0.01	0.1	0.03	0.1	0.13	0.6	0.00
P3-3	0.01	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00
P4-1	3.12	13.7	0.29	1.3	1.22	5.3	5.20	22.8	0.11
P4-2	0.10	0.4	0.01	0.1	0.03	0.1	0.13	0.6	0.00
P4-3	0.01	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00
P5-1	0.02	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00
P5-2	0.02	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00
P6-1	1.30	5.7	0.30	1.3	2.50	11.0	10.33	46.7	0.22
P6-2	0.65	2.9	0.10	0.4	0.00	0.0	0.00	0.0	0.00
P8-1N	0.15	0.7	0.04	0.2	0.00	0.0	0.00	0.0	0.00
P8-1S	0.15	0.7	0.04	0.2	0.00	0.0	0.00	0.0	0.00
P8-1A	0.03	0.1	0.00	0.0	0.00	0.0	0.00	0.0	0.00
P8-2N	0.15	0.7	0.04	0.2	0.00	0.0	0.00	0.0	0.00
P8-2S	0.15	0.7	0.04	0.2	0.00	0.0	0.00	0.0	0.00
P8-2A	0.03	0.1	0.00	0.0	0.00	0.0	0.00	0.0	0.00
P8-VE	0.07	0.3	0.00	0.0	0.00	0.0	0.00	0.0	0.00
P8-VW	0.07	0.3	0.00	0.0	0.00	0.0	0.00	0.0	0.00
P9-1	1.65	7.2	0.17	0.7	0.00	0.0	0.00	0.0	0.00
P10-1	1.65	7.2	0.17	0.7	0.00	0.0	0.00	0.0	0.00
P11-1	1.65	7.2	0.17	0.7	0.00	0.0	0.00	0.0	0.00
PKG-1	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00
PKG-2	0.10	0.4	0.00	0.0	0.00	0.0	0.00	0.0	0.00
MT-2	0.07	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00
MT-3	0.02	0.1	0.00	0.0	0.00	0.0	0.00	0.0	0.00
Fugitive Emissions									
Heaters	0.44	1.0	0.14	0.31	5.83	12.8	4.9	10.7	0.32
Total Pre-Project PTE	16.06	69.1	2.04	8.79	29.45	116.05	46.33	193.6	2.9

OC
T/hr
0.9
0.7
5.6
2.2
0.5
0.0
0.0
0.5
0.0
0.0
0.0
0.0
1.0
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
0.7
12

Table 7
Changes in Potential to Emit

Emissions Unit	$PM_{10}/PM_{2.5}$		SO2		NOx		CO		VO
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr
Point Sources									
Boiler I	-0.29	-1.30	-0.02	-0.09	-3.87	-16.95	-3.25	-14.20	-0.21
Boiler 3	-0.22	-1.00	-0.02	-0.09	-2.83	-12.40	-2.38	-10.40	-0.16
Boiler 5	-0.17	-0.80	-0.06	-0.26	-1.76	-7.70	-3.55	-15.60	-0.49
Boiler 4 and Temporary Boiler*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P3-1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P3-2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P3-3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P4-1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P4-2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P4-3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P5-1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P5-2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P6-1	-1.30	-5.70	-0.30	-1.31	-2.50	-11.00	-10.33	-46.70	-0.22
P6-2	-0.65	-2.90	-0.10	-0.44	0.00	0.00	0.00	0.00	0.00
P8-1N	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P8-1S	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P8-1A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P8-2N	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P8-2S	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P8-2A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P8-VE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P8-VW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P9-1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P10-1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P11-1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PKG-1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PKG-2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MT-2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MT-3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fugitive Sources									
Heaters	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Change in PTE with Proposed Operating Limit*									
lb/hr	-2.63		-0.50		-10.96		-19.51		-1.08
T/.yr		-11.7		-2.2		-48.1		-86.9	
Percentage of pre-project PTE	-16%	-17%	-25%	-25%	-37%	-41%	-42%	-45%	-37%
Change in PTE with Proposed Operating Limit* and Facility-Wide CO Emissions Limit									
lb/hr	-2.63		-0.50		-10.96		-19.51		-1.08
T/.yr		-11.7		-2.2		-48.1		-94.6	
Percentage of pre-project PTE	-16%	-17%	-25%	-25%	-37%	-41%	-42%	-49%	-37%

* Based on Enforceable Limit Preventing Simultaneous Operation of Boiler 4 and the Temporary Boiler.

OC
T/yr
-0.92
-0.70
-2.15
0.00
0.00
0.00
0.00
0.00
0.00
0.00
0.00
0.00
-0.97
0.00
0.00
0.00
0.00
0.00
0.00
0.00
0.00
0.00
0.00
0.00
0.00
0.00
0.00
0.00
0.00
0.00
-4.7
-40%
-4.7
-40%

Table 8
HAP Emissions Summary

Emissions Unit	Pre-Project			Post-Project			Change in HAP Emissions	
	Heat Rate, MMBtuh	HAP Emissions lb/hr	HAP Emissions ton/yr	Heat Rate, MMBtuh	HAP Emissions lb/hr	HAP Emissions ton/yr	lb/hr	ton/yr
Boiler 1	42.9	0.079	0.35	-	0.000	0.00	-0.079	-0.35
Boiler 3	28.6	0.053	0.23	-	0.000	0.00	-0.053	-0.23
Boiler 4	72.1	0.134	0.58	72.1	0.134	0.58	0.000	0.00
Boiler 5	24.5	0.045	0.20	-	0.000	0.00	-0.045	-0.20
Temporary Boiler	-	0.000	0.00	98.6†	0.183	0.64	0.183	0.64
P3-1	20.0	0.037	0.16	20.0	0.037	0.16	0.000	0.00
P3-2	0.5	0.001	0.00	0.5	0.001	0.00	0.000	0.00
P4-1	20.0	0.037	0.16	20.0	0.037	0.16	0.000	0.00
P4-2	0.5	0.001	0.00	0.5	0.001	0.00	0.000	0.00
P6-1	41.0	0.076	0.33	41.0	0.076	0.33	0.000	0.00
P7-1	0.5	0.001	0.00	0.5	0.001	0.00	0.000	0.00
Heaters	59.5*	0.110	0.24	59.5*	0.110	0.24	0.000	0.00
Total:	310.1*	0.574	2.27	312.7*	0.579	2.13	0.005	-0.14

† Annual emissions adjusted to reflect maximum 292 days of operation.

* On annual basis heaters are assumed to operate at a maximum of 50% of burner capacity.

Table 9
Comparison of Criteria Pollutant Emissions Between Boiler 4 and the Temporary Boiler

Pollutant	Emissions Rate, lb/MMlb steam		Change in Emission Rate	
	Boiler 4	Temporary Boiler	lb/MMlb steam	Percentage Decrease
$PM_{10}/PM_{2.5}$	9.17	0.62	-8.55	-93%
SO2	2.17	0.87	-1.30	-60%
NOx	169	53.59	-116	-68%
CO	188	54.37	-133	-71%
VOC	21.3	7.93	-13.4	-63%

Parameter	Value	Units
Constants		
station barometric pressure	0.85	atm
Fw, NG wet gas combustion factor	10,610	wscf/MMBtu
excess air	15%	-
flue gas temperature	550	°F
stack diameter	4.00	ft
Calculations		
stoichiometric flue gas	17,436	wscfm
flue gas, standard conditions	20,051	wscfm
flue gas, actual conditions	45,137	acfm
stack gas velocity	59.87	fps

Basis

From Table 19-2, EPA Test Method 19
NXT Burner performance data sheet
NXT Burner performance data sheet
field measurement

with excess air

Summary of Potential Emissions -
Shelley Facility of Basic American Foods

Stack Identification	Estimated Annual Emissions, tons				
	PM-10/2.5	SO2	NOX	CO	VOC
Boiler 4	2.40	0.73	44.40	49.3	5.68
Temp Boiler	0.2	1.0	31.1	16.0	2.3
P3-1	13.7	1.3	5.3	22.8	0.5
P3-2	0.4	0.1	0.1	0.6	0.0
P3-3	0.0	-	-	-	-
P4-1	13.7	1.3	5.3	22.8	0.5
P4-2	0.4	0.1	0.1	0.6	0.0
P4-3	0.0	-	-	-	-
P5-1	0.0	-	-	-	-
P5-2	0.0	-	-	-	-
P8-1N	0.6	0.2	-	-	-
P8-1S	0.6	0.2	-	-	-
P8-1A	0.1	-	-	-	-
P8-2N	0.6	0.2	-	-	-
P8-2S	0.6	0.2	-	-	-
P8-2A	0.1	-	-	-	-
P8-VE	0.3	-	-	-	-
P8-VW	0.3	-	-	-	-
P9-1	7.2	0.7	-	-	-
P10-1	7.2	0.7	-	-	-
P11-1	7.2	0.7	-	-	-
Pkg-1	0.0	-	-	-	-
PKG-2	0.2	-	-	-	-
MT-2	0.3	-	-	-	-
MT-3	0.1	-	-	-	-
Total - Point Sources	**56.7**	**7.3**	**86.5**	**111.9**	**9.0**
Fugitive Dust	3.10	-	-	-	-
Heaters	0.97	0.30	12.78	10.73	0.70
Total - Fugitive	**4.1**	**0.3**	**12.8**	**10.7**	**0.7**

APPENDIX B – POINT STACK RELEASE PARAMETERS

TABLE 2

POINT SOURCE STACK RELEASE PARAMETERS

Stack Identification	Source ID	Stack Release Type	Easting (X), m	Northing (Y), m	Base Elevation, m	Stack Height, ft	Temperature, °F	Exit Velocity, fps	Stack Diameter, ft
Boiler 1	BLR1	DEFAULT	408776.3	4802871.0	1409.1	33.7	390.0	40.74	2.50
Boiler 3	BLR3	DEFAULT	408790.3	4802871.0	1409.4	33.3	320.0	25.46	2.50
Boiler 4	BLR4	DEFAULT	408776.9	4802806.7	1409.1	38.5	360.0	29.18	4.00
Boiler 5	BLR5	DEFAULT	408852.5	4802690.0	1411.2	42.2	300.0	43.88	2.00
P3-1	P3_1	DEFAULT	408808.3	4802839.3	1408.9	66.5	163.0	55.85	4.47
P3-2	P3_2	DEFAULT	408804.0	4802845.7	1409.1	26.8	94.0	48.27	1.22
P3-3	P3_3	DEFAULT	408802.2	4802841.2	1408.9	34.1	97.0	26.78	1.36
P4-1	P4_1	DEFAULT	408808.3	4802832.6	1408.9	66.5	163.0	55.85	4.47
P4-2	P4_2	DEFAULT	408805.3	4802829.9	1409.0	27.3	102.0	44.80	1.26
P4-3	P4_3	DEFAULT	408801.3	4802830.5	1408.9	28.4	112.0	23.27	1.46
P5-1	P5_1	DEFAULT	408801.6	4802866.5	1409.4	24.4	85.0	51.57	0.33
P5-2	P5_2	DEFAULT	408801.0	4802858.2	1409.4	27.4	85.0	51.57	0.33
P6-1	P6_1	DEFAULT	408695.7	4802839.6	1408.6	50.8	127.0	48.79	3.50
P6-2	P6_2	DEFAULT	408720.1	4802844.8	1408.8	50.8	100.0	51.04	2.50
P8-1N	P8_1N	DEFAULT	408755.6	4802902.7	1409.4	35.4	112.0	37.80	2.00
P8-1S	P8_1S	DEFAULT	408755.6	4802900.6	1409.4	36.7	112.0	44.28	2.00
P8-1A	P8_1A	DEFAULT	408757.1	4802898.2	1409.3	35.1	90.0	52.53	0.83
P8-2N	P8_2N	DEFAULT	408751.3	4802902.7	1409.4	30.3	112.0	37.80	2.00
P8-2S	P8_2S	DEFAULT	408751.3	4802900.6	1409.4	30.7	112.0	44.28	2.00
P8-2A	P8_2A	DEFAULT	408749.8	4802897.5	1409.4	35.2	90.0	52.53	0.83
P8-VE	P8_VE	DEFAULT	408757.7	4802897.8	1409.3	33.2	85.0	50.93	0.50
P8-VW	P8_VW	DEFAULT	408757.7	4802899.4	1409.3	33.2	85.0	50.93	0.50
P9-1	P9_1	DEFAULT	408716.0	4802809.0	1408.8	59.0	102.0	41.65	4.00
P10-1	P10_1	DEFAULT	408708.0	4802809.0	1408.8	59.0	102.0	41.65	4.00
P11-1	P11_1	DEFAULT	408701.0	4802809.0	1408.8	59.0	102.0	41.65	4.00
Pkg-1	PKG_1	DEFAULT	408796.4	4802883.2	1409.4	31.1	80.0	49.96	0.99
Pkg-2	PKG_2	DEFAULT	408763.8	4802890.8	1409.1	31.1	80.0	43.85	0.83
MT-2	MT_2	DEFAULT	408770.5	4802817.1	1409.1	33.7	80.0	50.13	0.67
MT-3	MT_3	DEFAULT	408804.3	4802868.6	1409.4	50.1	80.0	51.57	0.33

APPENDIX C – AMBIENT AIR QUALITY IMPACT ANALYSES

M E M O R A N D U M DRAFT

DATE: June 10, 2020

TO: Christina Boulay, Permit Writer, Air Program

FROM: Kevin Schilling, Stationary Source Modeling Supervisor, Air Program

PROJECT: P-2011.0131 PROJ 62436, Permit to Construct (PTC) for temporary boiler operation a BAF potato processing facility located in Shelley, Idaho.

SUBJECT: Demonstration of Compliance with IDAPA 58.01.01.203.02 (NAAQS) and 203.03 (TAPs) as it relates to air quality impact analyses.

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Acronyms, Units, and Chemical Nomenclature

AAC	Acceptable Ambient Concentration of a non-carcinogenic TAP
AACC	Acceptable Ambient Concentration of a Carcinogenic TAP
acfm	Actual cubic feet per minute
AERMAP	The terrain data preprocessor for AERMOD
AERMET	The meteorological data preprocessor for AERMOD
AERMOD	American Meteorological Society/Environmental Protection Agency Regulatory Model
Appendix W	40 CFR 51, Appendix W – Guideline on Air Quality Models
ASOS	Automated Surface Observing System
BAF	Basic American Foods
BPIP	Building Profile Input Program
BRC	Below Regulatory Concern
CFR	Code of Federal Regulations
CMAQ	Community Multi-Scale Air Quality Modeling System
CO	Carbon Monoxide
Coal Creek	Coal Creek Environmental Associates
DEM	Digital Elevation Map
DEQ	Idaho Department of Environmental Quality
DV	Design Values
EL	Emissions Screening Level of a TAP
EPA	United States Environmental Protection Agency
GEP	Good Engineering Practice
hr	hours
Idaho Air Rules	Rules for the Control of Air Pollution in Idaho, located in the Idaho Administrative Procedures Act 58.01.01
ISCST3	Industrial Source Complex Short Term 3 dispersion model
K	Kelvin
lb/hr	Pounds per hour
m	Meters
m/sec	Meters per second
MMBtu	Million British Thermal Units
NAAQS	National Ambient Air Quality Standards
NAD83	North American Datum of 1983
NED	National Elevation Dataset
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen
NWS	National Weather Service
O_3	Ozone
OLM	Ozone Limiting Method
Pb	Lead
PM_{10}	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 10 micrometers

$PM_{2.5}$	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 2.5 micrometers
ppb	parts per billion
PRIME	Plume Rise Model Enhancement
PSD	Prevention of Significant Deterioration
PTC	Permit to Construct
PTE	Potential to Emit
PVMRM	Plume Volume Molar Ratio Method
SIL	Significant Impact Level
SO_2	Sulfur Dioxide
TAP	Toxic Air Pollutant
tpy	Tons per year
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compounds
ºF	Degrees Fahrenheit
$\mu g/m^3$	Micrograms per cubic meter of air

1.0 Summary

The Shelley Facility of Basic American Foods (BAF) submitted a Permit to Construct (PTC) application for operation of a temporary boiler at their existing potato processing plant located in Shelly, Idaho. An evaluation of project-specific air quality impacts of emission changes associated with the proposed modification were submitted to DEQ to demonstrate that applicable emissions do not result in violation of a National Ambient Air Quality Standard (NAAQS) or Toxic Air Pollutant (TAP) increment as required by the Idaho Administrative Procedures Act 58.01.01.203.02 and 203.03 (Idaho Air Rules Section 203.02 and 203.03). This memorandum provides a summary of the evaluation used to demonstrate compliance with applicable NAAQS and TAP increments.

Coal Creek Environmental Associates (Coal Creek), on behalf of BAF, prepared the PTC application and performed an evaluation of air quality impacts. DEQ review of submitted data and DEQ analyses summarized by this memorandum addressed only the rules, policies, methods, and data pertaining to the air impact analyses used to demonstrate that estimated emissions associated with operation of the facility will not cause or significantly contribute to a violation of any applicable air quality standard. This review did not address/evaluate compliance with other rules or analyses not pertaining to the air impact analyses. Evaluation of emission estimates was the responsibility of the DEQ permit writer and is addressed in the main body of the DEQ Statement of Basis, and emission calculation methods were not evaluated in this modeling review memorandum.

Table 1 presents key assumptions and results to be considered in the development of the permit. Idaho Air Rules require air impact analyses be conducted in accordance with methods outlined in 40 CFR 51, Appendix W *Guideline on Air Quality Models* (Appendix W). Appendix W requires that air quality impacts be assessed using atmospheric dispersion models with emissions and operations representative of design capacity or as limited by a federally enforceable permit condition.

The submitted information and analyses showed either a) that estimated potential/allowable emissions are at a level defined as below regulatory concern (BRC) and do not require a NAAQS compliance demonstration; b) that predicted pollutant concentrations from emissions associated with the project as modeled were below Significant Impact Levels (SILs) or other applicable regulatory thresholds; or c) that predicted pollutant concentrations from emissions associated with the project, when appropriately combined with co-contributing sources and background concentrations, were below applicable NAAQS at ambient air locations where and when the project has a significant impact. The application also showed that TAP emission increases associated with the project will not result in increased ambient air impacts exceeding allowable TAP increments. This conclusion assumes that conditions in Table 1 are representative of facility design capacity or operations as limited by a federally enforceable permit condition. The DEQ permit writer should use Table 1 and other information presented in this memorandum to generate appropriate permit provisions/restrictions to assure emissions do not exceed applicable regulatory thresholds requiring further analyses and to assure the requirements of Appendix W are met regarding emissions representative of design capacity or permit allowable rates.

Summary of Submittals and Actions

- May 2, 2020: Regulatory Start Date.
- June 1, 2020: Application determined complete by DEQ.

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES	
Criteria/Assumption/Result	**Explanation/Consideration**
General Emission Rates: Emission rates used in the air impact analyses, as listed in this memorandum, must represent maximum potential emissions as given by design capacity, inherently limited by the nature of the process or configuration of the facility, or as limited by the issued permit for the specific pollutant and averaging period.	Compliance has not been demonstrated for emission rates greater than those used in the air impact analyses.
Temporary Operation: Approval of this project is partially based on the temporary duration of the boiler and the cessation of production operations prior to 2021.	NAAQS compliance is not demonstrated to DEQ's satisfaction if operations continue beyond December 31, 2020.
No Simultaneous Operation with Boiler 4: Analyses were performed assuming Boiler 4 and the Temporary Boiler will not operate simultaneously.	NAAQS compliance is not assured if Boiler 4 is operating while the Temporary Boiler is operating.

2.0 Background Information

This section provides background information applicable to the project and the site proposed for the facility. It also provides a brief description of the applicable air impact analyses requirements for the project.

2.1 Project Description

The BAF Temporary Boiler project is a PTC modification for operations at the BAF Facility located in Shelley, Idaho. The 98.6 MMBtu/hour natural gas temporary boiler is needed because of unreliable existing boiler operation at the facility. BAF has deactivated Boilers 1 and 3, and BAF will operate the temporary boiler to complement Boiler 4. Also, the production line associated with stacks P6-1 and P6-2 is not operational and equipment has been removed. Finally, all production activities will cease at the Shelley facility by December 31, 2020.

2.2 Proposed Location and Area Classification

The facility is located Shelly, Idaho, within Bingham County (Northing: 4803050 m; Easting: 408715 m; UTM Zone 12). This area is designated as an attainment or unclassifiable area for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), lead (Pb), ozone (O_3), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), and particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$). The area is not classified as non-attainment for any criteria pollutants.

2.3 Air Impact Analyses Required for All Permits to Construct

Idaho Air Rules Sections 203.02 and 203.03:

> *No permit to construct shall be granted for a new or modified stationary source unless the applicant shows to the satisfaction of the Department all of the following:*
>
> ***02. NAAQS**. The stationary source or modification would not cause or significantly contribute to a violation of any ambient air quality standard.*
>
> ***03. Toxic Air Pollutants.** Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect*

human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.

Atmospheric dispersion modeling, using computerized simulations, is used to demonstrate compliance with both NAAQS and TAPs. Idaho Air Rules Section 202.02 states:

***02. Estimates of Ambient Concentrations**. All estimates of ambient concentrations shall be based on the applicable air quality models, data bases, and other requirements specified in 40 CFR 51 Appendix W (Guideline on Air Quality Models).*

2.4 Significant Impact Level and Cumulative NAAQS Impact Analyses

If specific criteria pollutant emission increases associated with the proposed permitting project cannot qualify for a BRC exemption as per Idaho Air Rules Section 221, then the permit cannot be issued unless the application demonstrates that applicable emission increases will not cause or significantly contribute to a violation of NAAQS, as required by Idaho Air Rules Section 203.02.

The first phase of a NAAQS compliance demonstration is to evaluate whether the proposed facility/project could have a significant impact to ambient air. Section 3.1.1 of this memorandum describes the applicability evaluation of Idaho Air Rules Section 203.02. The Significant Impact Level (SIL) analysis for a new facility or proposed modification to a facility involves modeling estimated criteria air pollutant emissions from the facility or modification to determine the potential impacts to ambient air. Air impact analyses are required by Idaho Air Rules to be conducted in accordance with methods outlined in Appendix W. Appendix W requires that facilities be modeled using emissions and operations representative of design capacity or as limited by a federally enforceable permit condition.

A facility or modification is considered to have a significant impact on air quality if maximum modeled impacts to ambient air exceed the established SIL listed in Idaho Air Rules Section 006 (referred to as a "significant contribution" in Idaho Air Rules) or as incorporated by reference as per Idaho Air Rules Section 107.03.b. Table 2 lists the applicable SILs.

If modeled maximum pollutant impacts to ambient air from the emission sources associated with a new facility or modification exceed the SILs, then a cumulative NAAQS impact analysis is necessary to demonstrate compliance with NAAQS and Idaho Air Rules Section 203.02.

A cumulative NAAQS impact analysis for attainment area pollutants involves assessing ambient impacts (typically the design values consistent with the form of the standard) from potential/allowable emissions resulting from the project and emissions from any nearby co-contributing sources (including existing emissions from the facility that are unrelated to the project), and then adding a DEQ-approved background concentration value to the modeled result that is appropriate for the criteria pollutant/averaging-period at the facility location and the area of significant impact. The resulting pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 2. Table 2 also lists SILs and specifies the modeled design value that must be used for comparison to the NAAQS. NAAQS compliance is evaluated on a receptor-by-receptor basis for the modeling domain.

Table 2. APPLICABLE REGULATORY LIMITS				
Pollutant	**Averaging Period**	**Significant Impact Levels[a] ($\mu g/m^3$)[b]**	**Regulatory Limit[c] ($\mu g/m^3$)**	**Modeled Design Value Used[d]**
PM_{10}[e]	24-hour	5.0	150[f]	Maximum 6th highest[g]
$PM_{2.5}$[h]	24-hour	1.2	35[i]	Mean of maximum 8th highest[j]
	Annual	0.2	12[k]	Mean of maximum 1st highest[l]
Carbon monoxide (CO)	1-hour	2,000	40,000[m]	Maximum 2nd highest[n]
	8-hour	500	10,000[m]	Maximum 2nd highest[n]
Sulfur Dioxide (SO_2)	1-hour	3 ppb[o] (7.8 $\mu g/m^3$)	75 ppb[p] (196 $\mu g/m^3$)	Mean of maximum 4th highest[q]
	3-hour	25	1,300[m]	Maximum 2nd highest[n]
	24-hour	5	365[m]	Maximum 2nd highest[n]
	Annual	1.0	80[r]	Maximum 1st highest[n]
Nitrogen Dioxide (NO_2)	1-hour	4 ppb (7.5 $\mu g/m^3$)	100 ppb[s] (188 $\mu g/m^3$)	Mean of maximum 8th highest[t]
	Annual	1.0	100[r]	Maximum 1st highest[n]
Lead (Pb)	3-month[u]	NA	0.15[r]	Maximum 1st highest[n]
	Quarterly	NA	1.5[r]	Maximum 1st highest[n]
Ozone (O_3)	8-hour	40 TPY VOC[v]	70 ppb[w]	Not typically modeled

a. Idaho Air Rules Section 006 (definition for significant contribution) or as incorporated by reference as per Idaho Air Rules Section 107.03.b.
b. Micrograms per cubic meter.
c. Incorporated into Idaho Air Rules by reference, as per Idaho Air Rules Section 107.
d. The maximum 1st highest modeled value is always used for the significant impact analysis unless indicated otherwise. Modeled design values are calculated for each ambient air receptor.
e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
f. Not to be exceeded more than once per year on average over 3 years.
g. Concentration at any modeled receptor when using five years of meteorological data.
h. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
i. 3-year mean of the upper 98th percentile of the annual distribution of 24-hour concentrations.
j. 5-year mean of the 8th highest modeled 24-hour concentrations at the modeled receptor for each year of meteorological data modeled. For the SIL analysis, the 5-year mean of the 1st highest modeled 24-hour impacts at the modeled receptor for each year.
k. 3-year mean of annual concentration.
l. 5-year mean of annual averages at the modeled receptor.
m. Not to be exceeded more than once per year.
n. Concentration at any modeled receptor.
o. Interim SIL established by EPA policy memorandum.
p. 3-year mean of the upper 99th percentile of the annual distribution of maximum daily 1-hour concentrations.
q. 5-year mean of the 4th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of 1st highest modeled 1-hour impacts for each year is used.
r. Not to be exceeded in any calendar year.
s. 3-year mean of the upper 98th percentile of the annual distribution of maximum daily 1-hour concentrations.
t. 5-year mean of the 8th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of maximum modeled 1-hour impacts for each year is used.
u. 3-month rolling average.
v. An annual emissions rate of 40 ton/year of VOCs is considered significant for O_3.
w. Annual 4th highest daily maximum 8-hour concentration averaged over three years.

If the cumulative NAAQS impact analysis indicates a violation of the standard, the permit may not be issued if the proposed project has a significant contribution (exceeding the SIL) to the modeled violation. If project-specific impacts are below the SIL, then the project does not have a significant contribution to the specific violations.

Compliance with Idaho Air Rules Section 203.02 is generally demonstrated if: a) applicable specific criteria pollutant emission increases are at a level defined as BRC, using the criteria established by DEQ regulatory interpretation[1]; or b) all modeled impacts of the SIL analysis are below the applicable SIL or other level determined to be inconsequential to NAAQS compliance; or c) modeled design values of the

cumulative NAAQS impact analysis (modeling all emissions from the facility and co-contributing sources, and adding a background concentration) are less than applicable NAAQS at receptors where impacts from the proposed facility/modification exceeded the SIL or other identified level of consequence; or d) if the cumulative NAAQS analysis showed NAAQS violations, the impact of proposed facility/modification to any modeled violation was inconsequential (typically assumed to be less than the established SIL) for that specific receptor and for the specific modeled time when the violation occurred.

2.5 Toxic Air Pollutant Analyses

Emissions of toxic substances are generally addressed by Idaho Air Rules Section 161:

> *Any contaminant which is by its nature toxic to human or animal life or vegetation shall not be emitted in such quantities or concentrations as to alone, or in combination with other contaminants, injure or unreasonably affect human or animal life or vegetation.*

Permitting requirements for toxic air pollutants (TAPs) from new or modified sources are specifically addressed by Idaho Air Rules Section 203.03 and require the applicant to demonstrate to the satisfaction of DEQ the following:

> *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Per Section 210, if the total project-wide emission increase of any TAP associated with a new source or modification exceeds screening emission levels (ELs) of Idaho Air Rules Section 585 or 586, then the ambient impact of the emission increase must be estimated. If ambient impacts are less than applicable Acceptable Ambient Concentrations (AACs) for non-carcinogens of Idaho Air Rules Section 585 and Acceptable Ambient Concentrations for Carcinogens (AACCs) of Idaho Air Rules Section 586, then compliance with TAP requirements has been demonstrated.

Idaho Air Rules Section 210.20 states that if TAP emissions from a specific source are regulated by the Department or EPA under 40 CFR 60, 61, or 63, then a TAP impact analysis under Section 210 is not required for that TAP. The DEQ permit writer evaluates the applicability of specific TAPs to the Section 210.20 exclusion.

3.0 Analytical Methods and Data

This section describes the methods and data used in the analyses to demonstrate compliance with applicable air quality impact requirements. The DEQ Statement of Basis provides a discussion of the methods and data used to estimate criteria and TAP emission rates.

3.1 Emission Source Data

Emissions of criteria pollutants and TAPs resulting from operation of the proposed modifications were estimated by Coal Creek for various applicable averaging periods. The calculation of potential emissions

is the responsibility of the DEQ permit writer, and the representativeness and accuracy of emission estimates is not addressed in this modeling memorandum. DEQ air impact analysts are responsible for assuring that potential emission rates provided in the emission inventory are properly used in the model. The rates listed must represent the maximum allowable rate as averaged over the specified period.

Emission rates used in the impact modeling applicability analyses and any impact analyses, as listed in this memorandum, should be reviewed by the DEQ permit writer and compared with those in the final emission inventory. All modeled criteria air pollutant and TAP emission rates must be equal to or greater than the facility's potential emissions calculated in the PTC emission inventory or proposed permit allowable emission rates.

3.1.1 Modeling Applicability and Modeled Criteria Pollutant Emission Rates

If project-specific emission increases for criteria pollutants would qualify for a BRC permit exemption as per Idaho Air Rules Section 221 if it were not for potential emissions of one or more pollutants exceeding the BRC threshold of 10 percent of emissions defined by Idaho Air Rules as significant, then a NAAQS compliance demonstration may not be required for those pollutants with emissions below BRC levels. DEQ's regulatory interpretation policy of exemption provisions of Idaho Air Rules is that: "A DEQ NAAQS compliance assertion will not be made by the DEQ modeling group for specific criteria pollutants having a project emissions increase below BRC levels, provided the proposed project would have qualified for a Category I Exemption for BRC emissions quantities except for the emissions of another criteria pollutant.[1]" The interpretation policy also states that the exemption criteria of uncontrolled potential to emit (PTE) not to exceed 100 ton/year (Idaho Air Rules Section 220.01.a.i) is not applicable when evaluating whether a NAAQS impact analyses is required. A permit will be issued limiting PTE below 100 ton/year, thereby negating the need to maintain calculated uncontrolled PTE under 100 ton/year. The BRC exemption cannot be used to exempt a project from a pollutant-specific NAAQS compliance demonstration in most cases where a PTC is required for the action regardless of emission quantities, such as the modification of an existing emission or throughput limit.

A NAAQS compliance demonstration must be performed for pollutant increases that would not qualify for the BRC exemption from the requirement to demonstrate compliance with NAAQS. Table 3 provides a comparison between emissions from the Temporary Boiler and BRC criteria.

Table 3. CRITERIA POLLUTANT NAAQS COMPLIANCE DEMONSTRATION REQUIREMENT APPLICABILITY

Criteria Pollutant	BRC Level (ton/year)	Applicable New Source PTE Emissions (ton/year)	Air Impact Analyses Required?
PM_{10} [a]	1.5	0.15	No
$PM_{2.5}$ [b]	1.0	0.15	No
Carbon Monoxide (CO)	10.0	12.8	Yes
Sulfur Dioxide (SO_2)	4.0	0.2	No
Nitrogen Oxides (NOx)	4.0	12.6	Yes
Lead (Pb)	0.06	0.0002	No
Volatile Organic Compounds (VOCs)	4.0	1.9	No

a. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.

Site-specific air impact modeling analyses may not be necessary for some pollutants, even where such emissions do not qualify for the BRC exemption. DEQ has developed modeling applicability thresholds, below which a site-specific modeling analysis is not required. DEQ generic air impact modeling analyses

that were used to develop the modeling thresholds provide a conservative SIL analysis for projects with emissions below identified threshold levels. Project-specific modeling applicability thresholds are provided in the *Idaho Air Modeling Guideline*[2]. These thresholds were based on assuring an ambient impact of less than the established SIL for specific pollutants and averaging periods.

If total project-specific emission rate increases of a pollutant are below Level I Modeling Applicability Thresholds, then project-specific air impact analyses are not necessary for permitting. Use of Level II Modeling Applicability Thresholds are conditional, requiring DEQ approval. DEQ approval is based on dispersion-affecting characteristics of the emission sources such as stack height, stack gas exit velocity, stack gas temperature, distance from sources to ambient air, presence of elevated terrain, and potential exposure to sensitive public receptors.

DEQ determined Level II Modeling Applicability Thresholds were appropriate for the project based on the following:

1) high stack height - only slightly below modeling used to generate Level II Thresholds;

2) stack temperature well above what was used to generate Level II Thresholds, which will increase plume rise and decrease ground-level impacts;

3) flow rates that are only slightly below those used to generate Level II thresholds;

4) there is a net decrease in emissions of all criteria pollutants because of the removal of Boilers 1, 3, and 5 and the removal of emissions from source P6-1 and P6-2;

5) emissions from production activities will cease after December 31, 2020.

Although the approximate 10-meter distance between the Temporary Boiler stack and the ambient air boundary is substantially less than what was used to generate Level II Thresholds (100 meters), DEQ determined Level II was still appropriate because of the offsetting emission sources. Table 4 provides a comparison between emissions for specific averaging periods and modeling applicability thresholds. A site-specific impact analysis was only triggered for 1-hour NOx.

Table 4. SITE-SPECIFIC CRITERIA POLLUTANT MODELING APPLICABILITY

Pollutant	Averaging Period	Emissions	Level I Modeling Thresholds	Level II Modeling Thresholds[a]	Site-Specific Modeling Required?
Carbon Monoxide (CO)	1-hour, 8-hour	3.7 lb/hr	15	175	No
Nitrogen Oxides (NOx)	1-hour	3.6 lb/hr	0.20	2.4	Yes
	Annual	12.6 ton/yr	1.2	14	No

a. DEQ determined Level II Modeling Thresholds are appropriate for this project.
b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
c. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.

Ozone (O_3) differs from other criteria pollutants in that it is not typically emitted directly into the atmosphere. O_3 is formed in the atmosphere through reactions of VOCs, NOx, and sunlight. Atmospheric dispersion models used in stationary source air permitting analyses cannot be used to estimate O_3 impacts resulting from VOC and NOx emissions from an industrial facility. O_3 concentrations resulting from area-wide emissions are predicted by using more complex airshed models such as the Community Multi-Scale Air Quality (CMAQ) modeling system. Use of the CMAQ model is very resource-intensive and DEQ asserts that performing a CMAQ analysis for a particular permit

application is not typically a reasonable or necessary requirement for air quality permitting. Addressing secondary formation of O_3 within the context of permitting a new stationary source has been somewhat addressed in EPA regulation and policy. As stated in a letter from Gina McCarthy of EPA to Robert Ukeiley, acting on behalf of the Sierra Club (letter from Gina McCarthy, Assistant Administrator, United States Environmental Protection Agency, to Robert Ukeiley, January 4, 2012):

> *. . . footnote 1 to sections 51.166(I)(5)(I) of the EPA's regulations says the following: "No de minimis air quality level is provided for ozone. However, any net emission increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of air quality data."*
>
> *The EPA believes it unlikely a source emitting below these levels would contribute to such a violation of the 8-hour ozone NAAQS, but consultation with an EPA Regional Office should still be conducted in accordance with section 5.2.1.c. of Appendix W when reviewing an application for sources with emissions of these ozone precursors below 100 TPY."*

DEQ determined it was not appropriate or necessary to require a quantitative source-specific O_3 impact analysis because allowable emission estimates of VOCs and NOx are below the 100 tons/year threshold.

Table 5 lists applicable emissions for a SIL analysis.

Table 5. EMISSIONS FOR NOx SIL ANALYSIS

Source / Description	1-hour NOx Emissions (pounds/hour)
Temporary Boiler – new source added	3.59
Boiler 1 – boiler removed	-3.87
Boiler 3 – boiler removed	-2.83
Boiler 5 – boiler removed	-1.76
Boiler 4 – boiler will not operate when the Temporary Boiler is operating	-10.16
P6-1 – no emissions because removal of the P6 production line	-10.33

3.1.2 TAPs Modeling Applicability

TAP emission regulations under Idaho Air Rules Section 210 are only applicable for new or modified sources constructed after July 1, 1995. Also, TAP emissions are only regulated on an incremental basis. Existing emissions are not considered in the evaluation.

The DEQ permit writer determined that the boiler is subject to 40 CFR 60, 61, or 63. Emissions of TAPs regulated by these sections are excluded from Idaho TAP requirements, as described in Section 2.5 of this memorandum. Emissions of all other TAPs (those not regulated by 40 CFR 60, 61, or 63) are below applicable ELs

3.1.3 Emission Release Parameters

Table 5 lists emission release parameters, including stack height, stack diameter, exhaust temperature, and exhaust velocity for emission sources evaluated in the air impact analyses. Emission point release parameters were based on information provided by the applicant.

Table 5. POINT SOURCE STACK PARAMETERS				
Release Point	**Stack Height (feet)**	**Stack Gas Flow Temp. (^{o}Fahrenheit)**	**Stack Gas Flow Velocity (feet/second)**	**Orient. of Release**
Temp. Boiler	30	550	60	capped
Boiler 1	34	390	41	vertical
Boiler 3	33	320	25	vertical
Boiler 4	38	134	23	vertical
Boiler 5	42	300	44	vertical
P6-1	51	127	49	vertical
P6-2	51	100	51	vertical

3.2 Background Concentrations

Background concentrations are used if a cumulative NAAQS impact analysis is needed to demonstrate compliance with applicable NAAQS. Cumulative NAAQS analyses were not required for this project because emissions either: 1) all criteria pollutants were below levels defined as BRC, and as such, a NAAQS compliance demonstration was not required for these emissions; or 2) DEQ determined that modeled impacts for this project were below SILs, and a cumulative impact analysis was not triggered.

3.3 Impact Modeling Methodology and Results

This section describes the modeling methods used by the applicant and DEQ to demonstrate preconstruction compliance with applicable air quality standards.

A semi-quantitative SIL analysis was performed for the project rather than the typical SIL analysis because of the following:

1) All production activities will cease at the facility by December 31, 2020. Therefore, certainty of NAAQS/SIL compliance is not as critical as for more permanent sources.

2) There is no production increase associated with the proposed modification and emission emissions associated with a unit level of production will decrease with use of the Temporary Boiler.

3) The 1-hour NO_2 NAAQS is a 3-year average of 1-hour design value impacts for each year (98th percentile of the distribution of maximum daily 1-hour concentrations). The SIL is also a 3-year average, but the design value impact is the maximum 1-hour concentration. EPA modeling policy allows use of a 5-year average if the meteorological data are available. If a new source will remain for less than one year, then the 3-year average would be substantially reduced.

4) The result of the project is a substantial reduction in NO_2 emissions. Although the magnitude of impacts associated with both the Temporary Boiler and the sources removed are nearly the same, the reductions do not offset impacts of the Temporary Boiler in time and space. Therefore, even though the project represents a net benefit in NO_2 impacts over the general area, a typical SIL analysis would show net impacts paired in time and space that exceed the SIL and trigger cumulative impact analysis.

Considering the points discussed above, DEQ determined that a typical SIL analysis is not appropriate for the Temporary Boiler project. To provide additional assurance of minimal impacts resulting from the project, Coal Creek performed specialized analyses. The analyses used the model setup from a previous impact analysis performed for the facility, with meteorological data from Idaho Falls airport. The emission rates shown in Table 5 were used in the SIL analysis. Figure 1 below, taken from the Coal Creek PTC application materials, shows receptors where the SIL was initially exceeded.

Coal Creek asserted that given the close proximity of impacted receptors to the emission source, little additional NO to NO_2 conversion would occur from the point of release to the atmosphere. Using an average NO_2/NOx ratio of 0.15, based on data from the BAF Blackfoot Facility Boiler 2A and the Madera Community Hospital boiler, the maximum net impact would effectively be equal to the SIL.

Coal Creek also performed an analysis to show where there were net air quality benefits from the sources removed. This was accomplished by modeling the removed sources as positive values and the Temporary Boiler as a negative value. NOx chemistry was not considered in this analysis, so the reduction in impacts is overstated somewhat. Also, DEQ did not verify that emissions from the removed sources could be realized in actual production operations. Figure 2 provides the plot of areas showing the maximum reduction in impacts.

4.0 Conclusions

The information and analyses submitted with the PTC application, combined with DEQ's review of those analyses, demonstrated to DEQ's satisfaction that emissions from the BAF Shelly Facility Temporary Boiler Project will not cause or significantly contribute to a violation of any applicable ambient air quality standard or TAP increment.

Figure 1: NO2 preliminary SIL analysis results (net impacts paired in time/space and no NOx chemistry)

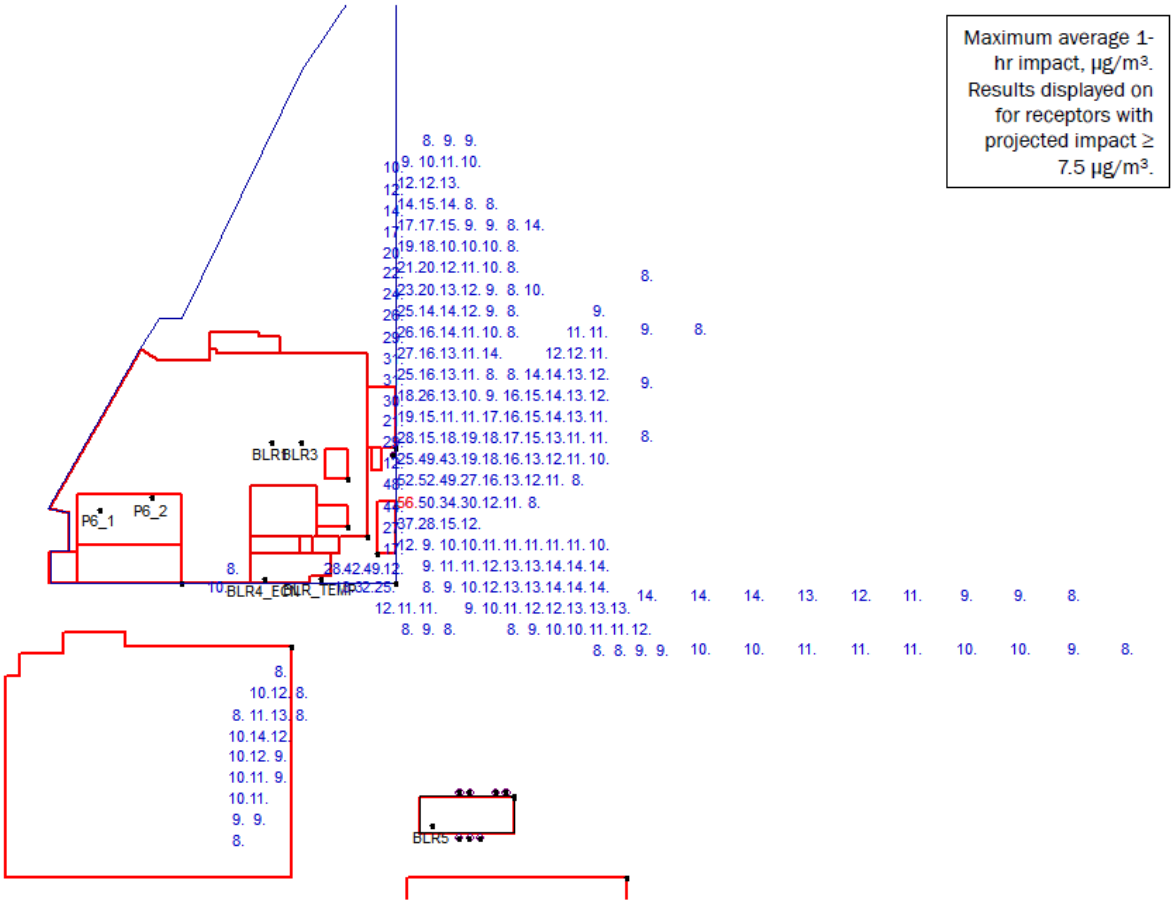
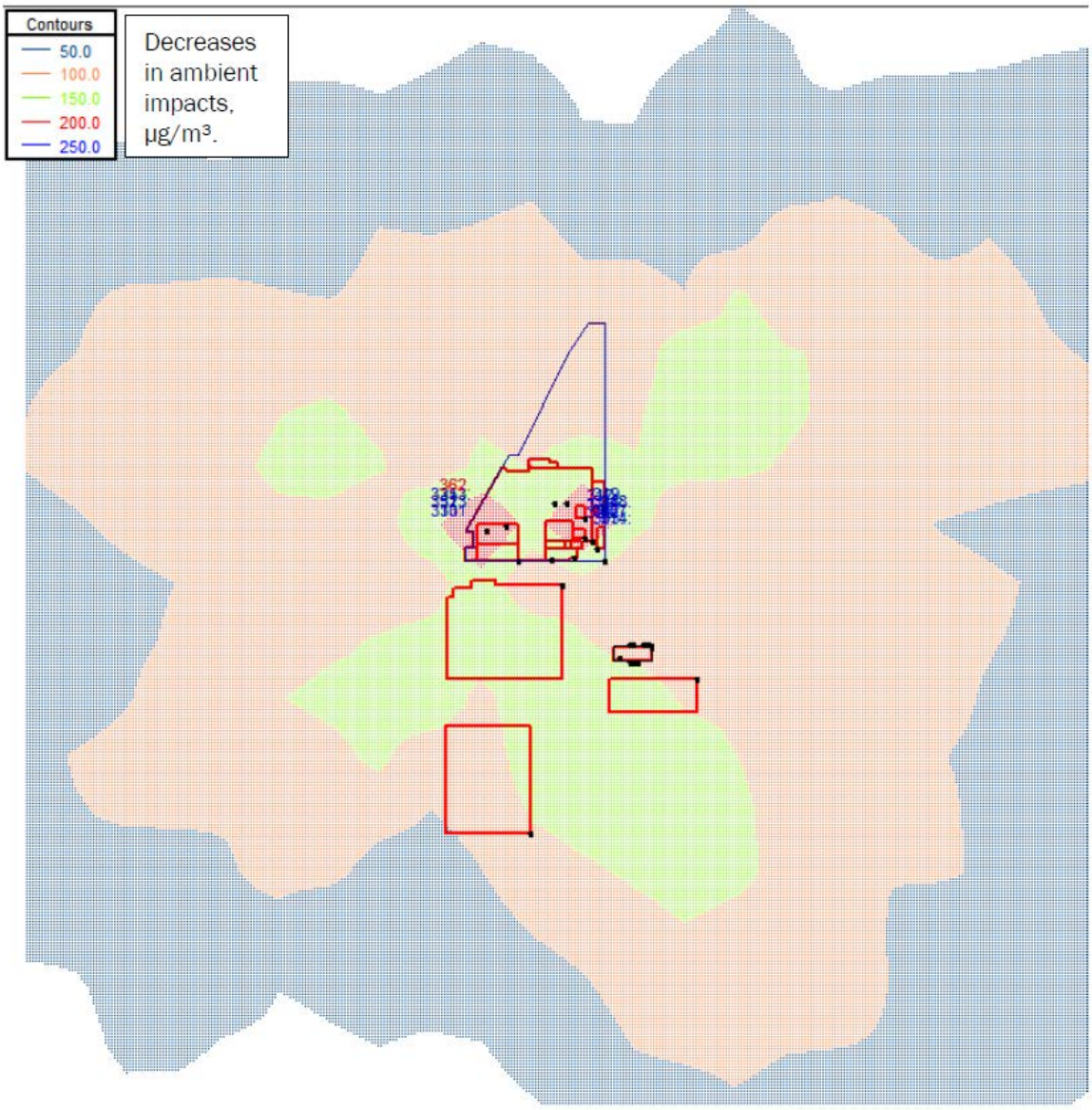


Figure 2: Maximum reduction in NO_2 impacts resulting from the Temporary Boiler Project.



References

1. *Policy on NAAQS Compliance Demonstration Requirements*. Idaho Department of Environmental Quality Policy Memorandum. July 11, 2014.

2. *State of Idaho Guideline for Performing Air Quality Impact Analyses*. Idaho Department of Environmental Quality. September 2013. State of Idaho DEQ Air Doc. ID AQ-011. Available at http://www.deq.idaho.gov/media/1029/modeling-guideline.pdf.

3. *Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard*. Office of Air Quality Planning and Standards. Air Quality Modeling Group. Research Triangle Park, NC. Guidance memorandum from R. Chris Owen and Roger Brode to Regional Dispersion Modeling Contacts. September 30, 2014.

APPENDIX D – FACILITY DRAFT COMMENTS

The following comments were received from the facility on July 27, 2020:

Facility Comment: None.

APPENDIX E – PROCESSING FEE

PTC Processing Fee Calculation Worksheet

Instructions:
Fill in the following information and answer the following questions with a Y or N. Enter the emissions increases and decreases for each pollutant in the table.

Company:	**Shelley Facility of Basic American**
Address:	**415 West Collins Road**
City:	**Blackfoot**
State:	**Idaho**
Zip Code:	**83221**
Facility Contact:	**Steve Brockett**
Title:	**Idaho Campus Environmental**
AIRS No.:	**311423**

N	Does this facility qualify for a general permit (i.e. concrete batch plant, hot-mix asphalt plant)? Y/N
Y	Did this permit require engineering analysis? Y/N
N	Is this a PSD permit Y/N (IDAPA 58.01.01.205.04)

Emissions Inventory			
Pollutant	Annual Emissions Increase (T/yr)	Annual Emissions Reduction (T/yr)	Annual Emissions Change (T/yr)
NO_X	0.0	35.46	-35.5
SO_2	0.0	1.99	-2.0
CO	0.0	94.6	-94.6
PM10	0.0	12.11	-12.1
VOC	0.0	2.88	-2.9
Total:	0.0	147.04	**-147.0**
Fee Due	**$ 1,000.00**		

Comments: