Statement of Basis

Permit to Construct No. P-2011.0040
Project ID 61314

The Amalgamated Sugar Company, LLC (TASCO-Paul)
Paul, Idaho

Facility ID 067-00001

Final

August 13, 2014
Morrie Lewis
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.

ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

ASTM	American Society for Testing and Materials
BACT	best available control technology
BAE	baseline actual emissions, as determined in accordance with 40 CFR 52.21(b)(48)
Boiler MACT	40 CFR 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters
B&W	Babcock & Wilcox
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CaO	calcium oxide (lime)
$CaCO_3$	calcium carbonate
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	CO_2 equivalent emissions
COMS	continuous opacity monitoring systems
cwt	hundred weight (1 cwt = 100 lb)
day/yr	calendar days per campaign year, beginning October 1 and ending the following year on September 30
DEQ	Department of Environmental Quality
EL	screening emission levels
EPA	U.S. Environmental Protection Agency
GHG	greenhouse gases
gpm	gallons per minute
gr/dscf	grains (1 lb = 7,000 grains) per dry standard cubic foot
HAP	hazardous air pollutants
ID No.	identification number
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
iwg	inches of water gauge
klb/yr	thousands of pounds per campaign year
lb/hr	pounds per hour
MACT	maximum achievable control technology
mg/L	milligrams per liter
MMBtu/hr	million British thermal units per hour
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
No.	number
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operation and maintenance
O_2	oxygen
PAE	projected actual emissions, as determined in accordance with 40 CFR 52.21(b)(41)
Pb	lead
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
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gauge
PTC	permit to construct
PTE	potential to emit

PW	process weight rate
QA/QC	quality assurance and quality control
QIP	Quality Improvement Plan
Rules	*Rules for the Control of Air Pollution in Idaho*
scf	standard cubic feet
SIP	State Implementation Plan
SO_2	sulfur dioxide
SO_x	sulfur oxides
T1	Tier I Operating Permit
T/day	tons per calendar day
T/hr	tons per hour
T/yr	tons per consecutive 12-calendar month period
TAP	toxic air pollutants
TASCO-Paul	The Amalgamated Sugar Company LLC, Paul Facility
U.S.C.	United States Code
VOC	volatile organic compounds

FACILITY INFORMATION

Description

The Amalgamated Sugar Company, LLC (TASCO-Paul) operates an existing beet sugar manufacturing plant that processes sugar beets into refined sugar, which is located in Paul, Idaho. The facility is also known as the Mini-Cassia Facility. Sugar beet processing operations consist of several steps, including diffusion, juice purification, evaporation, crystallization, molasses sugar recovery, and dried pulp manufacturing.

Prior to removing sucrose from sugar beets by diffusion, the cleaned and washed beets are sliced into long, thin strips called cossettes. In the diffusion step, the cossettes are conveyed to a continuous diffuser, in which hot water is used to extract sucrose. The sugar-enriched water that flows from the outlet of the diffuser is called "raw juice" and contains between 13% to 18% sugar. The raw juice proceeds to the juice purification operation. The processed cossettes, or pulp, leaving the diffuser is conveyed to the dried pulp manufacturing operation.

In the juice purification step, non-sucrose impurities in the raw juice are removed so that the pure sucrose can be crystallized. First, the juice passes through screens to remove any small cossette particles. The juice is then heated to 80-85°C (176-185°F) and proceeds to the liming system. In the liming system tank, milk of lime [$Ca(OH)_2$ aqueous solution] is added to the juice to absorb or adhere to the impurities. The juice is then sent to the first carbonation tank, where carbon dioxide (CO_2) gas is bubbled to precipitate the lime as insoluble calcium crystals. The lime kiln is used to produce the CO_2 and the lime, which are both used in carbonation; the lime is converted to milk of lime in a lime slaker. After filtration, the juice is softened. Then a small amount of sulfur dioxide (SO_2) is added to the juice to inhibit reactions that lead to darkening of the juice. Burning elemental sulfur in a sulfur stove produces the SO_2. Following the addition of SO_2, the juice (known as "thin juice") proceeds to the evaporators.

In the evaporation step, the sucrose in the juice is concentrated by removing water in a series of evaporators. Steam from boilers heats the first evaporator, and the steam from the water evaporated in the first evaporator heats the second evaporator, and so on through the final evaporator. After evaporation, the percentage of sucrose in the thick juice is 65% to 75%. Some of this thick juice is sent to storage tanks. Most of the thick juice is combined with crystalline sugars produced later in the process and dissolved in the high melter. The mixture is then filtered, yielding a clear liquid known as standard liquor, which proceeds to the crystallization operation.

In the crystallization step, sugar is crystallized by low-temperature pan boiling. The standard liquor is boiled in vacuum pans until it becomes supersaturated. To begin crystal formation, the liquor is "seeded" with finely milled sugar. When the crystals reach the desired size, the mixture of liquor and crystals, known as massecuite or fillmass, is discharged to the mixer. From the mixer, the massecuite is poured into high-speed centrifuges, in which the liquid is centrifuged into the outer shell, and the crystals are left in the inner centrifugal basket. The sugar crystals are washed with pure hot water, and then sent to the granulator/cooling system. After cooling, the sugar is screened and then either packaged or stored in large silos for future packaging. The liquid that was separated from the sugar crystals in the centrifuges is called syrup. This syrup is feed liquor for the second boiling step and is introduced back into a second set of vacuum pans. The crystallization/centrifugation process is repeated once again, resulting in the production of molasses.

In the molasses sugar recovery step, the molasses produced in the third boiling step can be used in the production of livestock feed. This molasses can be further desugarized using a separator process. However, the Mini Cassia facility does not have a separator so molasses is shipped to other factories for separation. The products of the separator process are "extract" (the high sugar fraction) and – "concentrated separator by product" (CSB, the low sugar fraction). The extract can be stored in tanks or immediately processed in the sugar operation, like thick juice. CSB can be used in the liquid form as livestock feed or can be added to the pulp.

In the dried pulp manufacturing step, wet pulp from the diffusion process is mechanically pressed to reduce the moisture content from about 95% to 75%. After pressing, the pulp can be sold as cattle feed or sent to the dryers. Before entering the rotary drum dryers, CSB or molasses is added to the pressed pulp. The pressed pulp is then dried by hot air in horizontal rotating drums known as pulp dryers. The pulp dryers can be fired by natural gas or coal. The dried pulp product is typically pelletized, but can be sold as livestock feed in both pelletized and unpelletized form.

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), superseded (S), or terminated (T).

Table 1 SUMMARY OF PERMITTING HISTORY

Issue Date	Permit Number	Project	Status	History Explanation
March 19, 1981	13-1020-0001-00 (067-00001)	Air pollution source permit, which established requirements for the boilers.	S	Initial permit for existing sources. Revised by 1020-0001.
January 1, 1984	1020-0001 (067-00001)	Air pollution source permit revision, which established requirements for the pulp dryers.	S	Initial permit for existing sources. Revised by P-020407.
September 23, 2002	P-020407 (067-00001)	Revised PTC to add No. 6 evaporator and establish throughput limits.	S	Revised 13-1020-0001. Revised by P-050401.
December 12, 2002	T1-9503-039-1 (067-00001)	Initial T1 operating permit.	S	Initial Title V operating permit. Revised by T1-030416.
February 3, 2005	P-050401	Revised PTC to replace the sugar production limit with a steam production limit.	S	Revised P-020407. Revised by P-050421.
July 27, 2005	P-050406	Initial PTC the Nebraska Boiler (backup).	A	Initial permit.
September 23, 2005	T1-030416	Renewal and administrative amendment T1 to incorporate compliance schedule and revisions resulting from an appeal.	A	Revised T1-9503-039-1. Revised by T1-050414 PROJ 0414.
November 17, 2005	P-050424	Initial PTC to add temporary emergency generator.	T	Superseded Director exemption issued 10/28/05. Terminated by letter O-050426 issued 1/06/06.
December 15, 2005	P-050421	Revised PTC to increase daily throughput limit.	S	Revised P-050401. Revised by P-060404.
June 14, 2006	P-060404	Revised PTC to increase annual throughput limit.	S	Revised P-050421. Revised by P-2007.0023.
May 16, 2007	P-2007.0023	Revised PTC to temporarily increase steam production in 2006.	S	Revised P-060404. Revised by P-2011.0040 PROJ 60754.
September 22, 2010	P-2010.0043	Initial PTC to replace lime kiln system.	S	Initial permit. Revised by P-2010.0043 PROJ 61012.
March 8, 2011	P-2011.0040 PROJ 60754	Revised PTC to revise campaign year definition.	S	Revised P-060404 and P-2007.0023. Revised by P-2011.0040 PROJ 61314.
June 1, 2012	P-2011.0043 PROJ 61012	Revised PTC to revise slaker control equipment.	S	Revised P-2010.0043. Revised by P-2011.0043 PROJ 61325.
June 11, 2012	P-2011.0040 PROJ 60995	Revised PTC to increase annual throughput and steaming rate limits.	S	Revised P-2011.0040 PROJ 60754. Revised by P-2011.0040 PROJ 61314.
March 18, 2014	P-2011.0043 PROJ 61325	Revised PTC to remove slaker control equipment.	A	Revised P-2011.0043 PROJ 61012.
August 13, 2014	P-2011.0040 PROJ 61314	Revised PTC to convert boilers to natural gas firing only, and to establish limits to resolve a historic equipment review required by T1-030416 compliance schedule.	A	Revised P-2011.0040 PROJ 60995.
Proposed	T1-050414 PROJ 0414	Renewal T1 to incorporate CAM and PTC revisions.	Proposed	Proposed renewal of T1-030416.

Project Scope

This PTC is a revision of existing PTC No. P-2011.0040 PROJ 60995 at an existing Tier I facility.

The applicant has proposed a boiler conversion project to:

- Modify the B&W Boiler to allow natural gas firing, and to limit all facility boilers to natural gas firing only.
- Credit enforceable annual emission limits (including limiting boilers to natural gas firing only) and other relevant federally-enforceable limits toward redressing historical modifications, and toward addressing the required compliance review of historical equipment changes.[1]

Historical Equipment Changes and Modifications

Emission increases resulting from at least five equipment changes at the facility were determined to have been modifications as defined in IDAPA 58.01.01.006.68, for which permit(s) were required but not obtained in accordance with IDAPA 58.01.01.200-220. These equipment changes are summarized in Table 3 of the Project Chronology section (below).

Of these projects, at a minimum the 1998 projects (construction of beet storage shed and juice storage tanks) were determined to have resulted in a PSD modification as defined in 40 CFR 52.21, with significant emission increases in CO, NO_x, SO_2, and PM/PM_{10}. A summary of the emission increases associated with these projects is provided in Table 2.

Table 2 HISTORICAL MODIFICATIONS 1986-2007

Description	CO [a] T/yr [b]	NO_x [a] T/yr [b]	SO_2 [a] T/yr [b]	PM/PM_{10} [a] T/yr [b]	VOC [a] T/yr [b]
1986-1987 Baseline Actual Emissions [c]	2,254	995	393	369	57
2007 Requested PTE [d]	2,929	1,712	665	508	57
1999-2007 Max. Reported Emissions [e]	*2,556*	*1,705*	*452*	*420*	*126*
Cumulative Net Emission Increases [f]	675	717	272	139	≥0
Significance Thresholds [g]	*100*	*40*	*40*	*15*	*40*

a) Regulated NSR Pollutant as defined in 40 CFR 52.21(b)(50).
b) Tons per calendar year.
c) Average of actual emissions over 1986-1987 for purposes of historical lookback annual emissions comparison.[2]
d) Potential to emit (PTE) as requested in 2007 to account for historical projects.
e) Maximum of reported annual emissions over 1999-2007 timeframe, shown only for comparison purposes.
f) Cumulative net change in emissions comparing requested PTE to 1986-1987 baseline.
g) Net emission increase and significant net emission increase thresholds as determined in accordance with 40 CFR 52.21(b)(40), 40 CFR 52.21(b)(23), and 40 CFR 52.21(b)(3)(i), except as noted to address the entire historical lookback timeframe.

[1] As required by compliance schedule, Permit Conditions 13.1-13.9 of Tier I Operating Permit T1-030416. Apparent PSD modifications resulting from unpermitted emissions increases resulting from both equipment changes and debottlenecking of existing equipment, as outlined in "PSD Applicability Determination," DEQ, October 14, 2007 (2008AAG1844[v2] and supporting emission estimates (2012AAG420[v3]).

[2] As updated in an attachment to "Presentations - Mini Cassia Facility," TASCO-Paul, February 10, 2009 (2012AAG933) and in "Updates to Supplemental Tier I," TASCO-Paul, January 31, 2007 (2008AAG1840).

Project Chronology

Table 3 HISTORICAL MODIFICATIONS AND BOILER CONVERSION PROJECT APPLICATION CHRONOLOGY

Date	Description
	Historical Modifications
1988-1989	Two juice storage tanks were installed. Each tank provided storage capacity not previously available, and allowed for increased utilization of the boilers.
1992	Two juice storage tanks were installed. Each tank provided storage capacity not previously available, and allowed for increased utilization of the boilers. A review of actual boiler steam data and emissions revealed that these changes did not result in a significant increase in any criteria pollutant.
1992	The B-side tower diffuser was replaced. This project improved efficiency of the process and allowed for increased beet processing. A review of actual steam boiler steam data and boiler emissions revealed that this change did not result in a significant increase in any criteria pollutant.
1992	Six beet slicers were installed and six others were upgraded. This project increased slicing capabilities, and improved slicing for higher juice extraction. This project was a contemporaneous change that allowed the facility to utilize the improved efficiency of the B-side diffuser and thick juice storage tank projects of 1992. A review of actual steam boiler steam data and boiler emissions revealed this change did not result in a significant increase in any criteria pollutant.
1998	Two juice storage tanks were installed. Each tank provided storage capacity not previously available, and allowed for increased utilization of the boilers. A review of actual boiler steam data and emissions revealed this change resulted in a significant increase in NO_x emissions.
1998	A beet storage shed was installed. Beets were previously stored outdoors, which limited the amount of time they could be stored before they rotted, thus inherently limiting utilization. The installation of the storage shed increased the time before rotting and thus allowed for greater utilization. This project, along with the installation of the thick juice storage tank allowed for greater utilization not previously available. A review of actual steam boiler steam data and boiler emissions revealed this change resulted in a significant increase in NO_x emissions.
1999-2007	Other projects may have allowed for additional increased utilization of the facility, including the addition of a fourth press and the replacement of the tower diffuser.[3]
2000	Two juice storage tanks were installed. Each tank provided storage capacity not previously available, and allowed for increased utilization of the boilers.
	Historical Modification Project[(a)]
February 5, 1998	DEQ received a request to construct two enclosed beet storage sheds, two additional juice storage tanks, improve beet handling and washing equipment, and increase plant beet throughput (2014AAG702).
February 19, 1998	DEQ determined that no PTC was required for the projects proposed on February 5, 1998, but requested submittal of a TAP exemption analysis for the project by 5/1/98 (2014AAG701).
April 29, 1998	DEQ received a letter requesting extension of the TAP exemption analysis deadline to 6/1/98 (2014AAG690).
June 1, 1998	DEQ received a TAP exemption analysis.
June 3, 1998	DEQ sent a letter acknowledging receipt of the TAP exemption analysis.
December 12, 2002	DEQ issued T1-9503-039-1 (067-00001), which included Compliance Schedule requirements requesting information concerning historical modifications – specifically the replacement of the 3rd, 4th, and 5th evaporators. (2011AAG3289).
May 20, 2003	DEQ sent a letter identifying three replacement evaporators for which permit applicability was not addressed, and a deadline to provide information on these sources by 5/20/2004 (2008AAG195).
September 1, 2004	DEQ received a Tier I renewal application, in which it was asserted that unpermitted PSD modifications were not triggered.
October 1, 2004	DEQ determined the Tier II/PTC application (addendum to Tier I application) incomplete (2008AAG1839).
October 14, 2004	DEQ and TASCO-Paul agreed to hold processing of the application while evaluating an application for similar projects at the TASCO-Nampa facility (2008AAG1842). No resolution was found.
June 15, 2005	DEQ received a revised Tier I renewal application.

[3] Refer to Section 4-2 of "Supplemental Tier I Operating Permit Application," TASCO-Paul, June 1, 2007 (2008AAG1861).

September 23, 2005	DEQ issued T1-030416, which included Compliance Schedule requirements requesting information concerning historical modifications (2011AAG3287, 20211AAG3288).
August 11, 2005	DEQ determined that the T1 renewal application was incomplete (2008AAG189), and requested information concerning historical modifications as required in the T1-030416 Compliance Schedule.
August 24, 2005	DEQ received a request to extend the T1-030416 expiration date until 12/12/06 (2014AAG679) to address requirements, including items requested in the incompleteness letter (8/11/05).
April 12, 2006	DEQ received draft emission estimates concerning historical equipment changes in 1988, 1992, and 1998 (2014AAG704).
May 25, 2006	DEQ received a revision to the application, including updated emission data and air quality impact analyses (2014AAG678).
June 12, 2006	DEQ received a revision to the application, including updated emissions data (2014AAG680).
September 29, 2006	DEQ met with TASCO-Paul to discuss historical projects.
October 12, 2006	DEQ met with TASCO-Paul to discuss plan for PSD review of historical projects.
December 13, 2006	DEQ determined the updated Tier I application was complete (2008AAG706).
December 15, 2006	DEQ determined the Tier II application was complete (2008AAG186).
January 31, 2007	DEQ received a revision to the application, including updated emissions data and air quality impact analyses, and proposed updates to the permit (2008AAG1840-1841).
June 1, 2007	DEQ received a revision to the application, incorporating an updated applicability review, emissions data, and air quality impact analyses (2008AAG1861-1869).
October 16, 2007	DEQ determined that historical changes qualified as modifications for which PTC were required and should have been obtained by TASCO-Paul (2008AAG1844[v1]).[1]
July 26, 2007	DEQ received a revision to the application, including updated emissions data (2008AAG148).
July 29, 2008	DEQ received a modeling protocol for a Class I air quality impact analyses (2008AAG2083).
September 23, 2008	DEQ received information concerning historical modifications, including emission calculations and proposed modeling analyses (2014AAG686).
October 28, 2008	DEQ received a modeling protocol for Class II air quality impact analyses (2008AAG2787).
February 10, 2009	DEQ received presentations concerning historical modifications (2012AAG933) and the modeling protocol.
February 18, 2009	DEQ met with federal land managers (FLM), EPA, and TASCO-Paul to address historical projects and relevant modeling analysis (2014AAG696).
March 16, 2009	DEQ received additional information concerning historical modifications, including emission calculations and proposed modeling analyses (2014AAG688).
April 10, 2009	DEQ met with FLM, EPA, and TASCO-Paul to address historical projects and relevant modeling analyses (2014AAG689).
April 20, 2009	DEQ received electronic copies of draft future emission inventories (2009AAG4449).
May 5, 2009	DEQ received draft future emission inventories (2009AAG4181).
June 3, 2009	DEQ sent a letter providing comments on proposed Class II Area analyses methodology and requesting additional information concerning regulatory applicability (2009AAG4503).
June 3, 2009	DEQ sent a letter providing comments on proposed Class I Area analyses methodology and requesting additional information concerning regulatory applicability and emission calculations (2009AAG4504, 2014AAG691).
June 8, 2009	DEQ received electronic copies of draft future emission inventories (2009AAG4549).
June 9, 2009	DEQ received supporting documentation for HAP emission factors relevant to historical modifications (2009AAG4537).
June 30, 2009	DEQ met with TASCO-Paul to address historical projects and relevant modeling analyses (2014AAG695).
January 22, 2010	DEQ received a proposed Class I modeling protocol (2014AAG697).
December 15, 2010	DEQ met with TASCO-Paul to address historical projects (2014AAG694).
February 10, 2012	DEQ provided a draft T1 renewal permit and statement of basis to the applicant, including a revised Compliance Schedule with revised requirements requesting additional analyses related to historical modifications (2012AAG229).
March 7, 2012	DEQ sent FLM a copy of information concerning historical modifications (2014AAG686).

April 13, 2012 and August 17, 2012	DEQ received comments from the facility concerning the draft T1 renewal documents and requesting a meeting regarding the Compliance Schedule (2012AAG1000, 2012AAG1021).
August 17, 2012	DEQ received comments from the applicant concerning the draft T1 renewal documents and requesting a meeting regarding the Compliance Schedule (2012AAG1000, 2012AAG1021, 2012AAG2473).
Boiler Conversion Project [(a)]	
December 31, 2013	DEQ received an application (2014AAG56).
January 2, 2014	DEQ received an application fee.
January 13 – 28, 2014	DEQ provided an opportunity to request a public comment period on the application and proposed permitting action (2014AAG57).
January 30, 2014	DEQ determined that the application was complete (2014AAG201).
March 18, 2014	DEQ received electronic modeling files from the applicant (2014AAG514).
April 2, 2014	DEQ made available a draft permit and statement of basis for peer and regional office review.
April 18, 2014	DEQ made available a draft permit and statement of basis for applicant review (2014AAG546, 2014AAG378[v1], 2014AAG377[v1]).
May 1 & 19, 2014	DEQ received comments from the applicant on the draft permit (2014AAG922, 2014AAG1015).
May 5, 2014	DEQ met with TASCO to discuss preliminary comments regarding the draft permit and to request an extension of the review deadline (2014AAG879, 2014AAG920).
May 23, 2014	DEQ made available updated draft T1 and PTC permits and statements of basis for applicant review, which addressed applicant comments and incorporated other recently issued PTC revisions (2014AAG988, 2008AAG197[v5], 2008AAG190[v3], 2014AAG378[v2], 2014AAG377[v2]).
June 13, 2014	DEQ received comments from the applicant on the draft permits (2014AAG1232).
June 24 – July 24, 2014	DEQ provided a public comment period for the proposed PTC and Tier I permitting actions (2014AAG1242, 2008AAG197[v6], 2008AAG190[v4], 2014AAG378[v3], 2014AAG377[v3]).
August 7, 2014	DEQ received a permit processing fee.
August 13, 2014	DEQ issued the final permit and statement of basis (2014AAG547, 2014AAG378[v4], 2014AAG377[v4]).

a) Additional discussion describing the relationship of the historical modification project to the boiler conversion project (and to the Tier I renewal project) immediately follows this table.

The historic equipment review initiated by DEQ in 2005 is resolved by issuance of this PTC. Tier I Operating Permit T1-030416, issued on September 23, 2005, included a compliance schedule to address permitting issues raised by equipment that was installed historically at TASCO-Paul. TASCO satisfied the compliance schedule and no further information, review, or enforcement is required by DEQ to resolve the historic equipment changes. Although TASCO disagrees with DEQ's conclusions regarding PSD applicability of certain historic projects, the proposed boiler emission reductions accomplished by this PTC address DEQ's conclusions with respect to increased utilization of the boilers resulting from historic equipment changes. The conditions of this PTC, therefore, fulfill the compliance schedule and DEQ's historic equipment review. The Tier I operating permit renewal can be issued without Section 13 (compliance schedule).

TECHNICAL ANALYSIS

Emission Sources and Control Equipment

Emission sources and control equipment are not expected to change as a result of this permitting action.

Table 4 EMISSION SOURCES AND CONTROL EQUIPMENT

Source Description		Control Equipment	Installation Date
<u>B&W Boiler (S–B1)</u> Operational capacity: Fuel consumption: Fuels:	 175,000 lb/hr steam 13.2 T/hr coal and/or natural gas [a]	Multiclone (A–B1A) and Spray-Chamber Scrubber (A–B1B) in series [a]	1952
<u>Erie City Boiler (S–B2)</u> Operational capacity: Fuel consumption: Fuels:	 250,000 lb/hr steam (gas) 220,000 lb/hr steam (coal) 16.8 T/hr coal and/or natural gas [a]	Multiclone (A–B2A) and Spray-Chamber Scrubber (A–B2B) in series [a]	1964
<u>Nebraska Boiler (S–B3, Backup Boiler Only)</u> Operational capacity: Fuel consumption: Fuels:	 200,000 lb/hr steam 250 MMBtu/hr natural gas	None	2005
<u>North Pulp Dryer (S–D2)</u> PW input rate: Fuel consumption: Fuels:	 56.9 T/hr 5.7 T/hr coal and/or natural gas	Dryer exhaust is split between two cyclones (A–D2A) that operate in parallel. Cyclone exhaust is D2A) that operate in parallel. Cyclone exhaust is combined and then split between two Spray-Impingement Scrubbers (A–D2B) that operate in parallel.	1969
<u>South Pulp Dryer (S–D1)</u> PW input rate: Fuel consumption: Fuels:	 48.5 T/hr 4.9 T/hr coal and/or natural gas	Dryer exhaust is split between two cyclones (A–D1A) that operate in parallel. Cyclone exhaust is combined and then split between two Spray-Impingement Scrubbers (A–D1B) that operate in parallel.	1961
<u>Pellet Cooler No. 1 (S–D3)</u> Manufacturer/Model: PW input rate:	 California Pellet Mill/2GA3 7.5 T/hr	Cyclone (A–D3)	Pre 1970
<u>Pellet Cooler No. 2 (S–D4)</u> Manufacturer/Model: PW input rate:	 California Pellet Mill/2GA3 7.5 T/hr	Cyclone (A–D4/5)	Pre 1970
<u>Pellet Cooler No. 3 (S–D5)</u> Manufacturer/Model: PW input rate:	 California Pellet Mill/2GA3 7.5 T/hr		1974
<u>Lime Kiln (S–K1)</u> Manufacturer: Model: Manufacture date: Maximum capacity: Maximum operation: Fuel: Fuel consumption:	 Eberhardt KR 8.0 (forced draft, vertical) 2011 770 T/day lime rock 146,300 T/yr lime rock anthracite coal and/or coke 55.2 T/day, 59 MMBtu/hr	Gas Washer First Carbonation Tank Second Carbonation Tank (A–K1)	2012
<u>Process Slaker (S–K2) – Eberhardt Process</u> Manufacturer: Model: Manufacture date: Maximum capacity: Maximum operation:	 May Foundry Eberhardt KR 8.0 2011 394 T/day CaO 74,860 T/yr CaO	None	2012

Source Description	Control Equipment	Installation Date
Drying Granulator (S–W1) Operational capacity: 73 T/hr wet sugar	Scrubber (A–W1)	Pre 1952
Cooling Granulator No. 1 (S–W2) Operational capacity: 73 T/hr wet sugar	Baghouse (A–W2)	Pre 1952
Cooling Granulator No. 2 (S–W3) Manufacturer/Model: BMA FCP 16/6/6 Operational capacity: 85 T/hr wet sugar	Baghouse (A–W3)	2012
Process Sugar Handling System (S–W4)	Process Sugar Baghouses (A–W4)	1967
Bulk Loadout Sugar Handling System (S–W5)	Bulk Loadout Baghouses (A–W5)	1994

a) The facility boilers will be limited to natural gas firing only, effective on the date of the Boiler MACT compliance deadline (Permit Condition 2.7). At such time, the listed control equipment will also no longer be required.

Emission Inventories

Emission inventories provided in the application included emissions of state-regulated toxic air pollutants (TAP), and federally-regulated criteria pollutants, hazardous air pollutants (HAP), and greenhouse gases (GHG).

Summaries of these emission inventories are provided below and in Appendix A.

Actual-to-Projected-Actual Emissions Increases for Boiler Conversion Project

As summarized in Table 5, upon completion of the boiler conversion project no apparent increase in federally-regulated air pollutants is expected, with the exception of volatile organic compounds (VOC). The emission increase of VOC is not expected to exceed the significant threshold; therefore, the boiler conversion project would not be applicable to PSD program requirements. The permittee has elected to use 2006-2007 for the baseline years (Table 5); coal was the primary boiler fuel source over this timeframe, accounting for 95% of overall fuel usage. Refer to the PSD Classification (40 CFR 52.21) section for additional information. The permittee has also reported estimated PAE is equivalent to the potential emissions (PTE) for the facility.

Table 5 BOILER CONVERSION PROJECT EMISSION INCREASES

Description	CO [b] T/yr [d]	NO_x [b] T/yr [d]	SO_2 [b] T/yr [d]	PM [a][b] T/yr [d]	VOC [b] T/yr [d]	Pb [b] T/yr [d]	H_2SO_4 [b] T/yr [d]	CO_2e [c] T/yr [d]
Baseline Actual Emissions [e]	139	521	96.7	122	1.39	5.27E-03	4.32	120,767
Projected Actual Emissions [e]	79.1	108	0.64	23.2	5.91	1.22E-04	0	113,073
Emission Increases [f]	-59.9	-413	-96.06	-98.8	4.52	-5.15E-03	-4.32	-7,694
Significance Thresholds [f]	*100*	*40*	*40*	*15*	*40*	*0.6*	*7*	*75,000*

a) PM, PM_{10}, and $PM_{2.5}$ emissions were estimated to be equivalent; significance threshold listed is for $PM_{2.5}$, the most stringent threshold when applying assumption.
b) Regulated NSR Pollutant as defined in 40 CFR 52.21(b)(50).
c) Tons of CO_2 equivalent emissions as defined in 40 CFR 52.21(b)(49).
d) Tons per "campaign year," as defined in Permit Condition 1.4.
e) Baseline and Projected Actual Emissions estimates include all emissions units at the facility ("facility-wide"). Baseline actual emissions used were average of actual emissions during the campaign years 2006-2007.
f) Net emission increase and significant net emission increase thresholds as determined in accordance with 40 CFR 52.21(b)(40), 40 CFR 52.21(b)(23), and 40 CFR 52.21(b)(3)(i).

The boiler conversion project is therefore not expected to result in a PSD significant net emission increase. Baseline Actual Emissions (BAE) and Projected Actual Emissions (PAE) were determined using New Source Review (NSR) Prevention of Significant Deterioration (PSD) procedures and definitions set forth in 40 CFR 52.21(a)(2)(iv)(*c*) and 40 CFR 52.21(b).

Toxic Air Pollutant Emissions Increases for Boiler Conversion Project

As summarized in Table 6, upon completion of the boiler conversion project no apparent increase in state-regulated toxic air pollutants (TAP) is expected, with the exception of formaldehyde. Although formaldehyde was estimated to exceed the emission screening level (EL), the applicant has demonstrated preconstruction compliance with TAP standards in accordance with IDAPA 58.01.01.210.

Table 6 BOILER CONVERSION PROJECT TAP EMISSION INCREASE EXCEEDING EL

TAP	HAP	Pre-Project lb/hr [(a)]	Post-Project lb/hr [(a)]	Increase lb/hr [(a)]	EL lb/hr [(b)]
Formaldehyde [(c)]	Formaldehyde	3.01E-03	1.83E-02	1.53E-02	5.10E-04

a) Project emission rates provided for comparison to EL were 24-hour average emission rates, which is assumed to be conservative when compared to annual average emission rates (overestimate of annual emission rates).
b) Screening emission level (EL) for carcinogenic TAP (formaldehyde) is an annual average emission rate.
c) Carcinogenic substance listed in IDAPA 58.01.01.586.

Historical Lookback Facility-Wide Emission Increases (1986-vs.-Projected Actual)

A comparison of historical and projected facility-wide emissions was undertaken in an effort to redress historical modifications (including PSD modifications) that occurred at the TASCO-Paul facility within the timeframe from 1986 until approximately 2007. Refer to the Project Chronology section for a summary of these historical modifications.

Up to five unpermitted equipment changes at the TASCO-Paul facility within this timeframe resulted in both a change in the method of operation of emissions units, and in net emissions increases. Collectively, these equipment changes:[1]

- allowed for the addition of a "juice run" operating scenario following the "beet campaign" operating scenario each operating season (i.e., "campaign year")
- included the addition of beet storage sheds and the replacement of process diffusers
- resulted in corresponding net emission increases, with at least one (or more) such emission increase exceeding the PSD NSR regulated pollutant applicability thresholds
- would have been subject to requirements and review under the PSD program

As provided in Table 7, when comparing 1986-1987 baseline emissions to the projected-actual emissions following the boiler conversion project, the boiler conversion project is expected to nearly return facility-wide emissions to pre-1987 emissions levels ("compliance netting" of emissions), with the exception of VOC and CO emissions.

Table 7 HISTORICAL LOOKBACK FACILITY-WIDE EMISSIONS COMPARISON

Description	CO [(a)] T/yr	NO_x [(a)] T/yr	SO_2 [(a)] T/yr	PM/PM_{10} [(a)] T/yr	VOC [(a)] T/yr
1986-1987 Baseline Actual Emissions [(b)]	2,254	995	393	369	57
Projected Actual Emissions [(c)]	2,905	856	127	258	156
Cumulative Net Emission Increases [(d)]	651	-139	-266	-111	99
Significance Thresholds [(e)]	*100*	*40*	*40*	*15*	*40*

a) Regulated NSR Pollutant as defined in 40 CFR 52.21(b)(50).
b) Average of actual emissions over 1986-1987 for purposes of the historical lookback review, with steam from coal combustion 99.7% by weight.[4]
c) Projected actual emissions estimates include all emissions units at the facility ("facility-wide"), with steam from natural gas combustion 100% by weight.
d) Cumulative net change in emissions comparing projected actual emissions to 1986-1987 baseline emissions.
e) Net emission increase and significant net emission increase thresholds as determined in accordance with 40 CFR 52.21(b)(40), 40 CFR 52.21(b)(23), and 40 CFR 52.21(b)(3)(i), except as noted to address the historical lookback timeframe.

[4] As updated in an attachment to "Presentations - Mini Cassia Facility," TASCO-Paul, February 10, 2009 (2012AAG933) and in "Updates to Supplemental Tier I," TASCO-Paul, January 31, 2007 (2008AAG1840).

Although not addressing surplus/excess emissions that occurred *during* the relevant lookback timeframe (1986 through 2007), by incorporating federally-enforceable emission limits in the permit pursuant to PSD program requirements, emissions at the beginning and at the end of the relevant timeframe are made comparable. A summary of these emission limits is provided in Table 8; refer to the Permit Conditions Review section for further discussion of these limits.

Table 8 FEDERALLY-ENFORCEABLE PERMIT CONDITIONS REQUIRED PURSUANT TO 40 CFR 52.21

Permit(s)	Condition(s)	Limit Description
P-2011.0040 PROJ 61314	2.2	Annual facility-wide beet throughput
T1-050414 PROJ 0414	3.3 [(a)]	
P-2011.0040 PROJ 61314	2.5	Annual boilers steam production
T1-050414 PROJ 0414	3.5 [(a)]	
P-2011.0040 PROJ 61314	2.6	Conversion of boilers to natural gas firing only
T1-050414 PROJ 0414	3.7 [(a)]	
P-2011.0040 PROJ 61314	2.15	No crediting of emission decreases toward PSD emissions netting (upon completion of boiler conversion to gas firing under condition 2.5)
T1-050414 PROJ 0414	3.14 [(a)]	
P-2011.0043 PROJ 61325	3.4	Coal sulfur content limits
T1-050414 PROJ 0414	3.30, 9.4 [(a)]	
P-2011.0043 PROJ 61325	3.7	Annual lime kiln lime rock input
T1-050414 PROJ 0414	9.7 [(a)]	
P-2011.0043 PROJ 61325	3.8	Daily lime kiln coal/coke combustion
T1-050414 PROJ 0414	9.8 [(a)]	

a) This PTC was processed in accordance with IDAPA 58.01.01.209.05.b, and the applicable requirements contained in this PTC have been incorporated into the Tier I operating permit renewal.

REGULATORY ANALYSIS

Attainment Designation (40 CFR 81.313)

This facility is located in Minidoka 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.

Permit to Construct (IDAPA 58.01.01.201)

An application was submitted requesting a revised PTC. Therefore, this permitting action was processed in accordance with the procedures of IDAPA 58.01.01.200-228. This PTC was processed in accordance with IDAPA 58.01.01.209.05.b, and the applicable requirements contained in this PTC have been incorporated into the Tier I operating permit renewal.

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

The Amalgamated Sugar Company, LLC is classified as a major facility as defined in IDAPA 58.01.01.008.10:

- The facility emits or has the potential to emit a regulated air pollutant in an amount greater than or equal to 100 T/yr (and greater than or equal to 250 T/yr);
- The facility emits or has the potential to emit a single regulated HAP in excess of 10 T/yr;
- The facility emits or has the potential to emit a combination of regulated HAP in excess of 25 T/yr.

TASCO-Paul has a fossil-fuel boiler (or combination thereof) of more than 250 MMBtu/hr heat input; therefore the boiler house (which includes the B&W Boiler, Erie City Boiler, and Nebraska Boiler) was classified as a designated facility as defined in IDAPA 58.01.01.006.30 and 40 CFR 52.21(b)(1)(i)(a), and fugitive emissions were included when determining the major facility classification in accordance with IDAPA 58.01.01.008.10.c.i, and when determining project net emissions increases in accordance with IDAPA 58.01.01.007 and 40 CFR 52.21(b)(48)(ii).

This PTC was processed in accordance with IDAPA 58.01.01.209.05.b, and the applicable requirements contained in this PTC have been incorporated into the Tier I operating permit renewal.

Refer to Appendix A for a summary of the regulated air pollutant emission estimates provided in the application.

PSD Classification (40 CFR 52.21)

Because the TASCO-Paul boiler house steam plant (which includes the B&W Boiler, Erie City Boiler, and Nebraska Boiler) has a fossil-fuel boiler (or combination thereof) of more than 250 MMBtu/hr heat input, the boiler house was classified as a designated facility as defined in IDAPA 58.01.01.006.30 and in 40 CFR 52.21(b)(1)(i)(a), and fugitive emissions were included when determining the major facility classification in accordance with IDAPA 58.01.01.008.10.c.i, and when determining project net emissions increases in accordance with IDAPA 58.01.01.007 and 40 CFR 52.21(b)(48)(ii).

The boiler house and the facility are classified as an existing major stationary source as defined in 40 CFR 52.21(b), because the boiler house emits and the facility emits or has the potential to emit criteria pollutants in an amount greater than 100 T/yr (and greater than 250 T/yr).

Although this section specifically addresses PSD applicability with regard to the boiler conversion project, because the historical lookback analysis was conducted within a compliance/enforcement regulatory framework (Table 7), a strict PSD regulatory applicability analysis was not used to address past PSD modifications, and was not examined here. Refer to the Emission Inventories section and Appendix A for a summary of regulated air pollutant emissions.

IDAPA 58.01.01.205 .... PERMIT REQUIREMENTS FOR NEW MAJOR FACILITIES OR MAJOR MODIFICATIONS IN ATTAINMENT OR UNCLASSIFIABLE AREAS.

40 CFR 52.21 .... Prevention of significant deterioration of air quality.

40 CFR 52.21(a)(2) .... Applicability procedures.

In accordance with §52.21(a)(2)(i), Prevention of Significant Deterioration (PSD) requirements apply to the construction of any new major stationary source or any project at an existing major stationary source in an area designated as attainment or unclassifiable.

This permit revision request was proposed for an existing major stationary source in an area designated as attainment or unclassifiable (refer to the Attainment Designation (40 CFR 81.313) section for additional information).

In accordance with §52.21(a)(2)(ii), the requirements of §52.21(j) through (r) apply to the construction of any new major stationary source or the major modification of any existing major stationary source, except as otherwise provided.

The boiler conversion project was not considered a major modification as defined in §52.21(b)(2)(i), because it was not predicted to result in a significant net emissions increase as determined in accordance with §52.21(b)(40). The net VOC emissions increase resulting from this permitting action was predicted to be less than the significant level as defined in §52.21(b)(23)(i) and as provided above in Table 5.

Except as provided below, §52.21(j) through (r)(5) were not determined to be applicable to this project. Additional information concerning this determination is provided in the paragraphs below regarding the emissions increase and net emissions increase calculations.

Emission increases

In accordance with §52.21(a)(2)(iv)(a), except as otherwise provided, a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—a significant emissions increase (as defined in §52.21(b)(40)), and a significant net emissions increase (as defined in §52.21(b)(3) and (b)(23)).

As provided in Table 5, the boiler conversion project was not predicted to cause a significant emissions increase or a significant net emissions increase.

In accordance with §52.21(a)(2)(iv)(b), the procedure for calculating (before beginning actual construction) whether a significant emissions increase (i.e., the first step of the process) will occur depends upon the type of emissions units being modified, according to §52.21(a)(2)(iv)(c) through (f). For these calculations, fugitive emissions (to the extent quantifiable) are included only if the emissions unit is part of one of the source categories listed in paragraph §52.21(b)(1)(iii) or if the emission unit is located at a major stationary source that belongs to one of the listed source categories. Fugitive emissions are not included for those emissions units located at a facility whose primary activity is not represented by one of the source categories listed in paragraph §52.21(b)(1)(iii) and that are not, by themselves, part of a listed source category. The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major stationary source (i.e., the second step of the process) is contained in the definition in §52.21(b)(3). Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.

The boiler emissions units are part of a listed source category in §52.21(b)(1)(iii), and fugitive emissions were included in the emissions increase estimates. In accordance with §52.21(a)(2)(iv)(*c*), the actual-to-projected actual test was used for this project because it involves existing emissions units. A significant emissions increase of a regulated NSR pollutant is not expected. The sum of the difference between projected actual emissions (as defined in §52.21(b)(41) and baseline actual emissions (as defined in §52.21(b)(48) for this permitting action did not equal or exceed pollutant significance thresholds as defined in §52.21(b)(23) and as provided in Table 5.

TASCO-Paul has elected to use actual production data from the 24-month period that includes the 2006-2007 beet processing campaign for the purposes of determining baseline actual emissions of all regulated NSR pollutants.

Reasonable Possibility Standard

In accordance with §52.21(r)(6), except as otherwise provided in paragraph (r)(6)(vi)(b) of this section, the provisions of this paragraph (r)(6) apply with respect to any regulated NSR pollutant emitted from projects at existing emissions units at a major stationary source (other than projects at a source with a PAL) in circumstances where there is a reasonable possibility, within the meaning of paragraph (r)(6)(vi) of this section, that a project that is not a part of a major modification may result in a significant emissions increase of such pollutant, and the owner or operator elects to use the method specified in paragraphs (b)(41)(ii)(a) through (c) of this section for calculating projected actual emissions.

Because NSR pollutant emission increases were not estimated to exceed applicable significance thresholds as shown in Table 5, and because federally-enforceable emission limits will be incorporated into the permit corresponding to projected-actual (potential) emissions, a "reasonable possibility" of exceeding significant thresholds is not anticipated. Refer to the Permit Conditions Review section for further discussion of these limits.

NSPS Applicability (40 CFR 60)

TASCO-Paul is subject to the requirements of 40 CFR 60 Subpart Db – New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units and Subpart A – General Provisions.

- The Nebraska "Backup" Boiler is an affected facility subject to NSPS requirements.
- The B&W Boiler could potentially become an affected facility subject to NSPS requirements following the proposed project (conversion to natural gas firing).

Because the B&W Boiler is undergoing equipment changes to allow for natural gas firing only – which could potentially meet the definition of modification and/or reconstruction under 40 CFR 60, Subpart A – NSPS applicability may be revisited and applicable requirements incorporated for this boiler as part of the next Tier I operating permit renewal.

Although initially the application included information specifying that the B&W Boiler conversion to natural gas firing would cause the boiler to become subject to NSPS Subparts A and Db, supporting regulatory analyses have since been revised by TASCO-Paul to indicate that the boiler is no longer expected to become applicable to these requirements.[5] The Tier I permit incorporates applicable federal requirements by reference, including applicable requirements from NSPS Subparts A and Db. The accuracy of these regulatory analyses may be revisited by following completion of the B&W Boiler conversion to natural gas firing.

NESHAP Applicability (40 CFR 61)

TASCO-Paul is not subject to any NESHAP standards in 40 CFR 61. The proposed permitting action is not expected to alter the applicability status of any emission source at the facility.

MACT Applicability (40 CFR 63)

The facility boilers (B&W Boiler, Erie City Boiler, and Nebraska Boiler) are subject to the requirements of 40 CFR 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters ("Boiler MACT"), because they are industrial boilers located at a major source of HAP. TASCO-Paul is classified as a major source of HAP; refer to the Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70) section for additional information concerning facility classification.

The abbreviated applicability analysis provided below assumes the conversion of all facility boilers to natural gas-only operation on or before the Boiler MACT compliance deadline of January 31, 2016 (as required by Permit Condition 2.7). Boiler MACT requirements applicable to boilers that historically have been able to combust coal (i.e., the B&W Boiler and the Erie City Boiler) would change if the boiler conversion project were not completed on or before this deadline as proposed.

Boiler MACT regulatory applicability should be addressed and applicable requirements incorporated as part of the next Tier I operating permit renewal.

<u>Subpart DDDDD</u>

40 CFR 63, Subpart DDDDD .... National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

40 CFR 63.7480 .... What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

40 CFR 63.7485 .... Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP, except as specified in §63.7491. For purposes of this subpart, a major source of HAP is as defined in §63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in §63.7575.

Because the permittee owns and operates industrial boilers at a major source of HAP and which are not specified under §63.7491, the requirements of this subpart are applicable.

40 CFR 63.7491 .... Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part.

(b) A recovery boiler or furnace covered by subpart MM of this part.

[5] "Additional Comments, TASCO-Paul Draft Permit to Construct P-2011.0040 PROJ 61314," TASCO-Paul, May 19, 2014 (2014AAG1015).

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

(d) A hot water heater as defined in this subpart.

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see §63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler or process heater is provided by regulated gas streams that are subject to another standard.

(j) Temporary boilers as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in §63.1200(b) is not covered by Subpart EEE.

Because the permittee owns and operates industrial boilers at a major source of HAP and which are not specified under §63.7491, the requirements of this subpart are applicable.

40 CFR 63.7495 .... When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by January 31, 2013, or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in §63.6(i).

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.

(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in §63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the switch from waste to fuel.

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for an exemption in §63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

In accordance with §63.7491(b), because the boilers are existing boilers, the compliance deadline is January 31, 2016 (unless extension is pursued in accordance with §63.6(i)).

Permit Conditions 2.11 – 2.12 include applicable requirements from this section.

High-level citation and incorporation of the federal standard by reference in accordance with IDAPA 58.01.01.107.03 were considered adequate provisions implementing the federal standard at this time.

Boiler MACT regulatory applicability should be addressed and applicable requirements incorporated as part of the next Tier I operating permit renewal.

40 CFR 63.7499 .... What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters, as defined in §63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

Upon completion of the boiler conversion project as proposed before the Boiler MACT compliance deadline (as required by Permit Condition 2.7), the boilers will only be designed to burn gas 1 fuels (natural gas only), and subject to regulation under subcategory §63.7499(l).

Permit Conditions Review

This section describes those permit conditions which have been added or revised in this permitting action. The requirements of this permit are not intended to contravene any permit conditions in any applicable Tier I or PTC permits. Refer to Table 1 in the Permitting History section for information regarding active permits, and refer to the Statement of Basis to Tier I Operating Permit No. T1-050414 PROJ 0414 for additional discussion concerning permit conditions which have not otherwise been addressed.

Permit conditions have been renumbered to facilitate incorporation into the Tier I operating permit. The permittee must continue to comply with all applicable requirements, as was assumed in the development of the emission inventories. This PTC was processed in accordance with IDAPA 58.01.01.209.05.b, and the applicable requirements contained in this PTC have been incorporated into the Tier I operating permit renewal.

Removed Permit Condition 2.1 of P-2011.0040 PROJ 60995

Emissions from any stack, vent, or functionally equivalent opening associated with the processing of beets or the production of sugar, shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60-minute period as required by IDAPA 58.01.01.625 (Rules for the Control of Air Pollution in Idaho). Opacity shall be determined by the procedures contained in IDAPA 58.01.01.625.

Because Tier I facility-wide Permit Condition 3.22 addresses and incorporates visible emissions requirements in accordance with IDAPA 58.01.01.625, this permit condition was determined to be duplicative in nature and was removed.

Revised Permit Conditions 2.3 and 2.5 (Permit Conditions 2.3 and 2.4 of P-2011.0040 PROJ 60995)

The annual throughput and production limits remain unchanged except as discussed below, but will be cited in the Tier I permit as federally-applicable requirements pursuant to the PSD regulatory program ("PSD-avoidance" limits).

Because projected actual emission (PAE) estimates were calculated as the maximum potential to emit of the facility boilers, this limit will no longer be required to limit PTE once coal firing has ceased. Because the date of boiler conversion (Permit Condition 2.7) encompasses part of the 2015 campaign year, the applicability of this limitation was extended through the end of the 2015 campaign year for the sake of simplifying applicable monitoring and recordkeeping requirements (Permit Condition 2.5).

Revised Permit Condition 2.7 (Permit Condition 2.5 of P-2011.0040 PROJ 60995)

Total coal usage in the B&W Boiler, the Erie City Boiler, and the Nebraska Boiler (combined) shall not exceed 104,900 tons of coal per campaign year (T/yr).

This permit condition was revised to limit the facility boilers to natural gas firing only, effective on the date of the Boiler MACT compliance deadline. Because the Nebraska Boiler does not have the capability for coal firing, reference to this boiler has been removed from the annual coal usage limitation.

Removed Permit Condition 2.6, 2.7, and 2.11 of P-2011.0040 PROJ 60995

All reasonable precautions shall be taken to prevent PM from becoming airborne as required in IDAPA 58.01.01.651. In determining what is a reasonable, consideration will be given to factors such as the proximity of dust-emitting operations to human habitations and/or activities and atmospheric conditions that might affect the movement of PM. Some of the reasonable precautions include, but are not limited to, the following:

- *Use, where practical, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of lands;*
- *Application, where practical, of asphalt, oil, water or suitable chemicals to, or covering of dirt roads, material stockpiles, and other surfaces which can create dust;*
- *Installation and use, where practical, of hoods, fans and fabric filters or equivalent systems to enclose and vent the handling of dusty materials. Adequate containment methods should be employed during sandblasting or other operations;*
- *Covering, where practical, of open-bodied trucks transporting materials likely to give rise to airborne dusts;*
- *Paving of roadways and their maintenance in a clean condition, where practical; or*
- *Prompt removal of earth or other stored material from streets, where practical.*

The permittee shall comply with the Air Pollution Emergency Rules in IDAPA 58.01.01.550-562.

The permittee shall conduct a monthly facility-wide inspection of potential sources of fugitive emissions, during daylight hours and under normal operating conditions to ensure that the methods used to reasonably control fugitive emissions are effective. If fugitive emissions are not being reasonably controlled, the permittee shall take corrective action as expeditiously as practicable. The permittee shall maintain records of the results of each fugitive emission inspection. The records shall include, at a minimum, the date of each inspection and a description of the following: the permittee's assessment of the conditions existing at the time fugitive emissions were present (if observed); any corrective action taken in response to the fugitive emissions; and the date the corrective action was taken.

Because Tier I facility-wide Permit Conditions 3.16 – 3.19 address and incorporate fugitive emissions requirements in accordance with IDAPA 58.01.01.651 and air pollution emergency requirements in accordance with IDAPA 58.01.01.550-562, these permit conditions were determined to be duplicative in nature and were removed.

Added Permit Condition 2.9

This permit condition requires notification to ensure compliance with the boiler coal burner and coal delivery system shutdown requirement (Permit Condition 2.7).

Added Permit Condition 2.10

This permit condition requires an initial performance test to measure the carbon monoxide (CO) emission rate in accordance with IDAPA 58.01.01.211.04, in order to verify the accuracy of B&W Boiler projected-actual CO emission estimates based on burner manufacturer estimates of CO concentrations of 100 ppm @ 3% O_2 on a dry basis, a developed emission factor of 9.50E-02 lb CO/1000 lb steam, and projected-actual ("future") estimated emission rates (lb/hr) as provided in Appendix A.[6]

With consideration given to initial verification testing and ongoing boiler work practice requirements required by the Boiler MACT,[7] additional CO testing was not required beyond the requirements of an initial verification test.

With consideration given to the NSPS requirement for continuous monitoring of NO_x emissions and because potential emission estimates were calculated on the basis of this emission limit, additional NO_x testing was also not required beyond the requirements of NSPS Subpart Db.

Added Permit Conditions 2.11 – 2.12, and 2.16

These permit conditions incorporate federally applicable requirements from NESHAP Subparts A and DDDDD.

Although initially the application included information specifying that the B&W Boiler conversion to natural gas firing would cause the boiler to become subject to NSPS Subparts A and Db, supporting regulatory analyses have since been revised by TASCO-Paul to indicate that the boiler is no longer expected to become applicable to these requirements. The Tier I permit incorporates applicable federal requirements by reference, including applicable requirements from NSPS Subparts A and Db.

Revised Permit Condition 2.13 (Permit Condition 2.12 of P-2011.0040 PROJ 60995)

The permittee shall monitor the facility-wide emissions of PM, PM_{10}, $PM_{2.5}$, SO_2, NO_x, and CO each calendar year for a period of 10 years following the issuance of this permit in accordance with 40 CFR 52.21(r)(6). Records of annual emissions shall be calculated and maintained in tons per year on a calendar year basis.

This permit condition was revised to account for the conversion of the facility boilers to natural gas firing only, effective on the date of the Boiler MACT compliance deadline. Because this requirement was relevant only to coal firing in the boilers, this requirement will no longer be applicable once the conversion project has been completed.[8] The deadline for this recordkeeping requirement was therefore revised for consistency with the Boiler MACT compliance deadline.

Added Permit Condition 2.15

This permit condition forbids the use of emission decreases from the boiler conversion project in netting calculations under the PSD regulatory program.

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6 Refer to Section 5.3.2 (Section 3C emission factors) of the boiler conversion project application, TASCO-Paul, December 31, 2013 (2014AAG56).

7 Burner tune-ups, as referenced in the application and as specified in 40 CFR 63.7540(a).

8 Refer to discussion concerning this permit condition in the "Permit Conditions Review" section in Statement of Basis to P-2011.0040 PROJ 60995, DEQ, June 11, 2012 (2012AAG588).

Because facility-wide emission reductions resulting from the conversion of facility boilers to natural gas firing only have been used in this permitting action toward redressing historical modifications,[1] these reductions cannot otherwise be used to offset emissions in future permitting projects. Emission reductions represent a "compliance netting" of past excess/surplus emissions that were not explicitly permitted in prior permitting actions. Refer to the analysis and discussion of historical lookback facility-wide emission increases in the Emission Inventories section for additional information concerning this permit condition.

PUBLIC REVIEW

Public Comment Period

A public comment period was provided in accordance with IDAPA 58.01.01.209.05.b. During this time, no comments were received with respect to DEQ's proposed permit to construct. Refer to the Project Chronology section for public comment period dates.

APPENDIX A – EMISSION INVENTORIES

B&W Boiler Natural Gas Conversion Project
Mini Cassia Facility

PROJECTED ACTUAL EMISSIONS *or* PTE FOR PROJECTED ACTUAL EMISSIONS

Emissions Unit	PM[a]	SO_2	NO_x	CO	VOC	LEAD	SULFURIC ACID
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Point Sources							
B&W Boiler - Natural Gas Firing	23.4	0.64	108	79.1	5.91	1.22E-04	0
Total Projected Actual Emissions	23.4	0.64	108	79.1	5.91		

BASELINE ACTUAL EMISSIONS

Emissions Unit	PM[a]	SO_2	NO_x	CO	VOC	LEAD	SULFURIC ACID
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Point Sources							
B&W Boiler - Coal Firing	122	96.7	521	139	1.39	5.27E-03	4.32
Total Baseline Actual Emissions	122	96.7	521	139	1.39		

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

Emissions Unit	PM[a]	SO_2	NO_x	CO	VOC	LEAD	SULFURIC ACID
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Project Emissions Increase	-98.6	-96.06	-413	-59.9	4.52	-5.15E-03	-4.32
PSD Significance Emission Rate (SER) *See 40 CFR 52.21(b)(23)*	15	40	40	100	40	0.6	7
Does the Project Emissions Increase Exceed the Significant Emissions Rate Threshold?	No	No	No	No	No	No	No

[a] PM, PM10, PM2.5

B&W Boiler Natural Gas Conversion Project
Mini Cassia Facility

PROJECTED ACTUAL EMISSIONS *or* PTE FOR PROJECTED ACTUAL EMISSIONS

Emissions Unit	CO_2	CH_4	N_20	CO_2e
	T/yr	T/yr	T/yr	T/yr
Point Sources				
B&W Boiler - Natural Gas Firing	120640	2.3	0.2	120767
Total Projected Actual Emissions	120640	2.3	0.2	120767

BASELINE ACTUAL EMISSIONS

Emissions Unit	CO_2	CH_4	N_20	CO_2e
	T/yr	T/yr	T/yr	T/yr
Point Sources				
B&W Boiler - Coal Firing	112207	13	1.8	113073
Total Baseline Actual Emissions	112207	13	1.8	113073

/PARISON OF THE PROJECT EMISSIONS INCREASE TO THE SIGNIFICANT EMISSIONS RATE THRESHO

Emissions Unit	CO_2	CH_4	N_20	CO_2e
	T/yr	T/yr	T/yr	T/yr
Project Emissions Increase	8433	-10.7	-1.6	7694
PSD Significance Emission Rate (SER) *See 40 CFR 52.21(b)(23)*	NA	NA	NA	75000
Does the Project Emissions Increase Exceed the Significant Emissions Rate Threshold?	NA	NA	NA	No

[a] PM, PM10, PM2.5

PRE- AND POST PROJECT NON-CARCINOGENIC TAP EMISSIONS SUMMARY
POTENTIAL TO EMIT
B & W Boiler Natural Gas Conversion Project
Mini Cassia Facility

Non-Carcinogenic Toxic Air Pollutants (sum of all emissions)	Pre-Project [a] 24-hour Average Emissions Rates for Units at the Facility (lb/h)	Post-Project [b] 24-hour Average Emissions Rates for Units at the Facility (lb/h)	Change in 24-hour Average Emissions Rates for Units at the Facility (lb/h)	Non-Carcinogenic Screening Emission Level (lb/h)	Exceeds Screening Level? (Y/N)
Acetophenone	1.88E-04		-1.88E-04	none	NO
Acrolein	3.64E-03		-3.64E-03	1.70E-02	NO
Antimony	2.26E-04		-2.26E-04	3.30E-02	NO
Barium	4.82E-01	1.07E-03	-4.81E-01	3.30E-02	NO
Benzyl Chloride	8.79E-03		-8.79E-03	none	NO
Carbon Disulfide	1.63E-03		-1.63E-03	2.00E+00	NO
2-chloroacetophenone	8.79E-05		-8.79E-05	2.10E-02	NO
Chlorobenzene	2.76E-04		-2.76E-04	2.33E+01	NO
Chromium (total)	3.26E-03	3.41E-04	-2.92E-03	3.30E-02	NO
Cobalt	1.26E-03	2.05E-05	-1.24E-03	3.30E-03	NO
Cumene	6.65E-05		-6.65E-05	1.63E+01	NO
Cyanide	3.14E-02		-3.14E-02	3.33E-01	NO
Dichlorobenzene	0.00E+00	2.92E-04	2.92E-04	3.00E+01	NO
2,4-Dinitrotoluene	3.52E-06		-3.52E-06	none	NO
Dimethyl Sulfate	6.03E-04		-6.03E-04	none	NO
Ethyl Benzene	1.18E-03		-1.18E-03	2.90E+01	NO
Ethyl Chloride	5.27E-04		-5.27E-04	1.76E+02	NO
Ethylene Dichloride	5.02E-04		-5.02E-04	2.67E+00	NO
Fluorides, as F	7.53E-02		-7.53E-02	1.67E-01	NO
Hexane	8.41E-04	4.38E-01	4.38E-01	1.20E+01	NO
Hydrogen Chloride	6.64E-02		-6.64E-02	5.00E-02	NO
Hydrogen Fluoride	8.00E-02		-8.00E-02	none	NO
Isophorone	7.28E-03		-7.28E-03	1.87E+00	NO
Lead	5.27E-03	1.22E-04	-5.15E-03	none	NO
Magnesium	1.38E-01		-1.38E-01	6.67E-01	NO
Manganese	6.15E-03	9.26E-05	-6.06E-03	3.33E-01	NO
Mercury	1.04E-03	6.33E-05	-9.79E-04	none	NO
Methyl Bromide	2.01E-03		-2.01E-03	1.27E+00	NO
Methyl Chloride	6.65E-03		-6.65E-03	6.87E+00	NO
Methyl Ethyl Ketone	4.90E-03		-4.90E-03	3.93E+01	NO
Methyl Methacylate	2.51E-04		-2.51E-04	2.73E+01	NO
Methyl Tert Butyl Ether	4.39E-04		-4.39E-04	none	NO
Napthalene	1.63E-04		-1.63E-04	3.33E+00	NO
Pentane	0.00E+00	6.33E-01	6.33E-01	1.18E+02	NO
Phenol	2.01E-04		-2.01E-04	1.27E+00	NO
Propionaldehyde	4.77E-03		-4.77E-03	2.87E-02	NO
Selenium	1.63E-02	5.85E-06	-1.63E-02	1.30E-02	NO
Styrene	3.14E-04		-3.14E-04	6.67E+00	NO
Sulfuric Acid	4.32E+00		-4.32E+00		NO
Toluene	3.01E-03	8.28E-04	-2.19E-03	2.50E+01	NO
Xylene (total)	4.65E-04		-4.65E-04	2.90E+01	NO
Vinyl Acetate	9.54E-05		-9.54E-05	none	NO

[a] Coal Fired
[b] Natural Gas Fired

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

Carcinogenic Toxic Air Pollutants (sum of all emissions)	Pre-Project [a] 24-hour Average Emissions Rates for Units at the Facility (lb/h)	Post-Project [b] 24-hour Average Emissions Rates for Units at the Facility (lb/h)	Change in 24-hour Average Emissions Rates for Units at the Facility (lb/h)	Carcinogenic Screening Emission Level (lb/h)	Exceeds Screening Level? (Y/N)
Acetaldehyde	7.16E-03		-7.16E-03	3.00E-03	NO
Arsenic Compounds	7.79E-02	4.87E-05	-7.79E-02	1.50E-06	NO
Benzene	2.47E-01	5.12E-04	-2.46E-01	8.00E-04	NO
Beryllium Compounds	3.99E-03	2.92E-06	-3.99E-03	2.80E-05	NO
Bis (2-ethylhexyl) phthalate	9.17E-04		-9.17E-04	2.80E-02	NO
Cadmium Compounds	9.69E-03	2.68E-04	-9.42E-03	3.70E-06	NO
Chloroform	7.41E-04		-7.41E-04	2.80E-04	NO
Chromium 6+ Compounds	9.92E-04	3.41E-04	-6.51E-04	5.60E-07	NO
Ethylene Dibromide	1.51E-05		-1.51E-05	3.00E-05	NO
Formaldehyde	3.01E-03	1.83E-02	1.53E-02	5.10E-04	YES
Methyl Hydrazine	2.13E-03		-2.13E-03	2.20E-05	NO
Methylene Chloride	5.51E-02		-5.51E-02	1.60E-03	NO
Nickel	5.32E-02	5.12E-04	-5.27E-02	2.70E-05	NO
PAHs	3.95E-03	2.03E-05	-3.93E-03	9.10E-05	NO
POM	2.61E-04	2.03E-05	-2.41E-04		NO
Tetrachloroethylene	5.40E-04		-5.40E-04	1.30E-02	NO
1,1,1 - Trichloroethane	2.51E-04		-2.51E-04	4.20E-04	NO

[a] Coal Fired
[b] Natural Gas Fired

Facility HAP Potential to Emit
Emissions Summary

HAP Pollutants	PTE (t/y)
Acetaldehyde	7.96
Acrolein	1.86
Formaldehyde	1.82
Methanol	84.02
Arsenic	0.03
Benzene	0.09
Beryllium	0.00
Cadmium	0.09
Chromium	0.02
Cyanide	0.19
Hydrochloric Acid	0.15
Hydrogen Fluoride	0.46
Lead	0.03
Manganese	0.04
Mercury	0.01
Nickel	0.02
Selenium	0.10
Toluene	0.02
Xylenes	0.00
PAH and other HAPs	0.27

SUMMARY OF CRITERIA POLLUTANT EMISSIONS - Future
Mini Cassia Facility

Table I

3500000
206.00 Beet run (days)
125.00 Juice run (days)

Source	ID	PM			PM10			SO2			CO			NOx			VOC		
		max lbs/hr	avg lbs/h	year tns/yr	max lbs/hr	avg lbs/h	year tns/yr	max lbs/hr	avg lbs/h	year tns/yr	max lbs/hr	avg lbs/h	year tns/yr	max lbs/hr	avg lbs/h	year tns/yr	max lbs/hr	avg lbs/h	year tns/yr
..W Boiler	S-B1	52.8	22.8	100.1	52.8	22.8	100.1	41.8	18.1	79.2	60.0	26.0	113.8	235.6	101.9	446.4	0.9	0.4	1.7
Erie City Boiler	S-B2	67.3	27.0	118.3	67.3	27.0	118.3	52.8	19.6	86.0	7.7	10.6	46.3	283.8	131.3	575.0	1.1	0.9	4.0
South Pulp Dryer	S-D1	44.1	18.0	78.7	44.1	18.0	78.7	27.4	11.6	51.0	287.3	117.0	512.4	78.9	33.4	146.5	1.8	0.7	3.3
North Pulp Dryer	S-D2	45.5	18.4	80.8	45.5	18.4	80.8	31.9	13.7	59.9	349.4	141.6	620.1	77.5	33.2	145.5	2.1	0.9	3.9
Pellet Cooler No. 1	S-D3	2.40	0.84	3.68	1.20	0.42	1.84												
Pellet Cooler No. 2	S-D4	2.40	0.84	3.68	1.20	0.42	1.84												
Pellet Cooler No. 3	S-D5	2.40	0.84	3.68	1.20	0.42	1.84												
		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00
Eberhardt Kiln	S-K1	3.10	1.61	7.06	3.10	1.61	7.06	0.92	0.49	2.14	690.2	359.1	1572.7	20.22	20.22	46.08	1.21	0.64	2.80
Process Slaker	S-K2	0.46	0.24	1.05	0.46	0.24	1.05												
Drying Granulator	S-W1	0.73	0.54	2.35	0.73	0.54	2.35												
#1 Cooling Granulator	S-W2	0.37	0.27	1.18	0.37	0.27	1.18												
#2 Cooling Granulator	S-W3	0.37	0.27	1.18	0.37	0.27	1.18												
Sugar Handling(Process)	S-W4	0.30	0.30	1.31	0.30	0.30	1.31												
Sugar Handling(Bulk Loading)	S-W5	0.30	0.30	1.31	0.30	0.30	1.31												
Main Mill	S-O5																61.5	30.2	132.3
Sulfur Stoves	S-O7							5.5	2.7	11.9									
Coal Unloading Area	F-O1					0.03	0.15												
Coal Storage Area	F-O2					0.80	3.51												
Boiler Coal Unloading area & Haul Road	F-B3					0.11	0.50												
Beet Hauling - West & Loop	F-O4 (a-e)					0.74	3.24												
Beet Hauling - East	F-O4 (f-l)					1.13	4.97												
Beet Hauling - North - East	F-O4 (j)					0.17	0.74												
Cooling Towers	F-O6					0.92	4.02												
Dr[illegible]r Coal Unloading	F-D6					0.01	0.06												
[illegible] Pulp Storage & Loadout	F-D7					0.10	0.45												
[illegible] Storage & Handling	F-O8 (a-e)					0.90	3.94												
TOTAL	TOTAL	222.6	92.3	404.4	219.0	96.0	420.4	160.4	66.2	290.2	1394.6	654.2	2865.3	696.0	320.1	1359.5	68.5	33.8	148.0

APPENDIX B – AMBIENT AIR QUALITY IMPACT ANALYSES

Formaldehyde
Air Quality Impact Analysis

B & W Boiler Natural Gas Conversion Project

for the

The Amalgamated Sugar Company LLC
Mini Cassia Facility
Paul, Idaho

December 31, 2013

1.0 INTRODUCTION

The Amalgamated Sugar Company LLC (TASCO) is proposing to replace the B&W boiler coal firing system and associated equipment with a new natural gas firing system. The exhaust gases from the B&W boiler will pass through the existing economizer and then out through a new stack. TASCO has conducted an ambient air quality impact analysis in support of the B&W Boiler natural gas conversion project at the Mini Cassia facility. The analysis was performed to conservatively estimate air quality impacts for the net difference in converting the B&W Boiler from Coal firing to natural gas firing only.

The modeling analysis was performed using the air dispersion model "Breeze" developed by Trinity Consultants. The Breeze suite of programs combines into one program EPA's AERMOD and Building Profile Input Program (BPIP). The Breeze suite is also capable of importing digital elevation model (DEM) terrain files and graphically presenting contours as well as buildings, emission points and receptors.

2.0 INPUT PARAMETERS

The air dispersion model for the proposed B&W Natural Gas Conversion Project utilized stack parameters previously accepted by the Department for the Nebraska natural gas fired boiler. Table 1 presents the emission rate, stack location and base elevation. Table 2 details the stack parameters including stack height and diameter, exhaust temperature and the exhaust flow rate. Figure 1 illustrates the projected source location for the B&W Boiler Natural Gas Stack (PB1a) and the dark bold circle indicates the area the projected stack would be located. Building outlines are shown for reference as are some of the other stacks located onsite. The new B&W Stack will be located north of the location of the current stack and scrubbing system. For natural gas firing the source was modeled assuming 8760 hours of operation at 190,000 lbs / hr steam rate. The emission source was modeled at 1264 meters (4147 ft) grade level at the site.

3.0 MODEL

The Breeze Suite of programs operates using EPA's AERMOD model version 12060, BPIP Prime model version 04274 and AERMAP version 11103

4.0 METEOROLOGY

This analysis used meteorological data (met data) developed by Geomatrix of Lynwood, Washington using EPA's AERMET model (Version 06431). Upper air data was collected from the Boise, Idaho meteorology station #24131 while the surface air was collected at the Burley, Idaho met station #25867. Land use characteristics were processed in 12 sectors encompassing the Minidoka INEEL meteorological site using the AERMET user guide lookup tables. These files reflect meteorology of the area from January, 2000 to December31, 2004.

5.0 RECEPTOR GRID

The dispersion model included boundary receptors and two receptor grids. Figure 2 illustrates the fence line receptors and grid receptors. Figure 3 illustrates the location of the Highest Annual concentration identified in this model.

The full receptor grid consists of several receptor grids. Originally, receptors were placed every 200 meters on a 10 km by 15 km area grid, (3750 grid points) with the facility placed in the middle. Receptors were excluded within the facility boundaries, which includes the beet handling area, waste ponds, coal storage area, irrigation fields and the physical plant due to restricted public access. Fence line receptors were placed every 50 meters. Based upon the results of initial simulations, a refined 2 km by 2 km receptor grid with 50 meter spacing between receptors was placed around the facility with an eastern most boundary at the public road 400 West. The smaller grid is represented by grid patterns of 41 by 41 (1681) receptors. The placement of the smaller 50-meter grid pattern was determined by evaluating previous model output and prevailing wind patterns.

Terrain elevations for the receptors were obtained from USGS digital elevation model (DEM) 7.5-minute Rupert, Rupert_NW, Burley and Burley_NE quadrangles. These data have a horizontal spatial resolution of 30 meters. The receptor locations are expressed in units of UTM (NAD27) coordinates.

6.0 BACKGROUND CONCENTRATION

Background concentrations are not necessary for this impact analysis.

7.0 RESULTS

Table 3 presents the results of the analysis. The highest annual, model-predicted formaldehyde concentration is 1.43E-03 ug/m^3 (1.9% of AAAC) and is located at UTM Coordinates 273,362 meters Easting by 4,721,371 meters Northing. Figure 3 illustrates the location of the maximum model-predicted concentrations. The highest concentration occurs at the western property boundary.

8.0 CONCLUSIONS

An air quality impact analysis was conducted based on net annual emissions changes associated with converting this boiler from coal firing to natural gas firing.

As shown in Table 3, the analysis demonstrated that the model-predicted formaldehyde concentrations for the meteorological period between January 1, 2000 and December 31, 2004 are less than the Acceptable Annual Ambient Concentrations (AAAC) in Idaho's carcinogenic list in IDAPA 58.01.01.586.

Table 1. Modeled TAP's Emissions - Point Sources (lbs / hour)

Emission Source	Source ID	Annualized Net Emissions Changes (Lb/hr)
		Formaldehyde
B & W Natural Gas Fired Boiler Project	P-B1a	1.53E-02

Table 2. Stack Data for Stationary Point Sources

Emission Source (Point)	Source ID	UTM X (m)	UTM Y (m)	Stack Height (ft)	Temperature (°F)	Exit Velocity (ft / min)	Stack Diameter (ft)
B & W Natural Gas Fired Boiler	P-B1a	273,810	4,721,195	69	380	3709	6.0

Table 3. Maximum Predicted Annual Concentration

Constituent	Annual (ug / m^3)	UTM X (m)	UTM Y (m)	AAAC's (ug / m^3)
Formaldehyde	1.43E-03	273,362	4,721,371	7.70E-02

Figure 1. Facility Layout Showing Buildings, Tanks, and Stacks

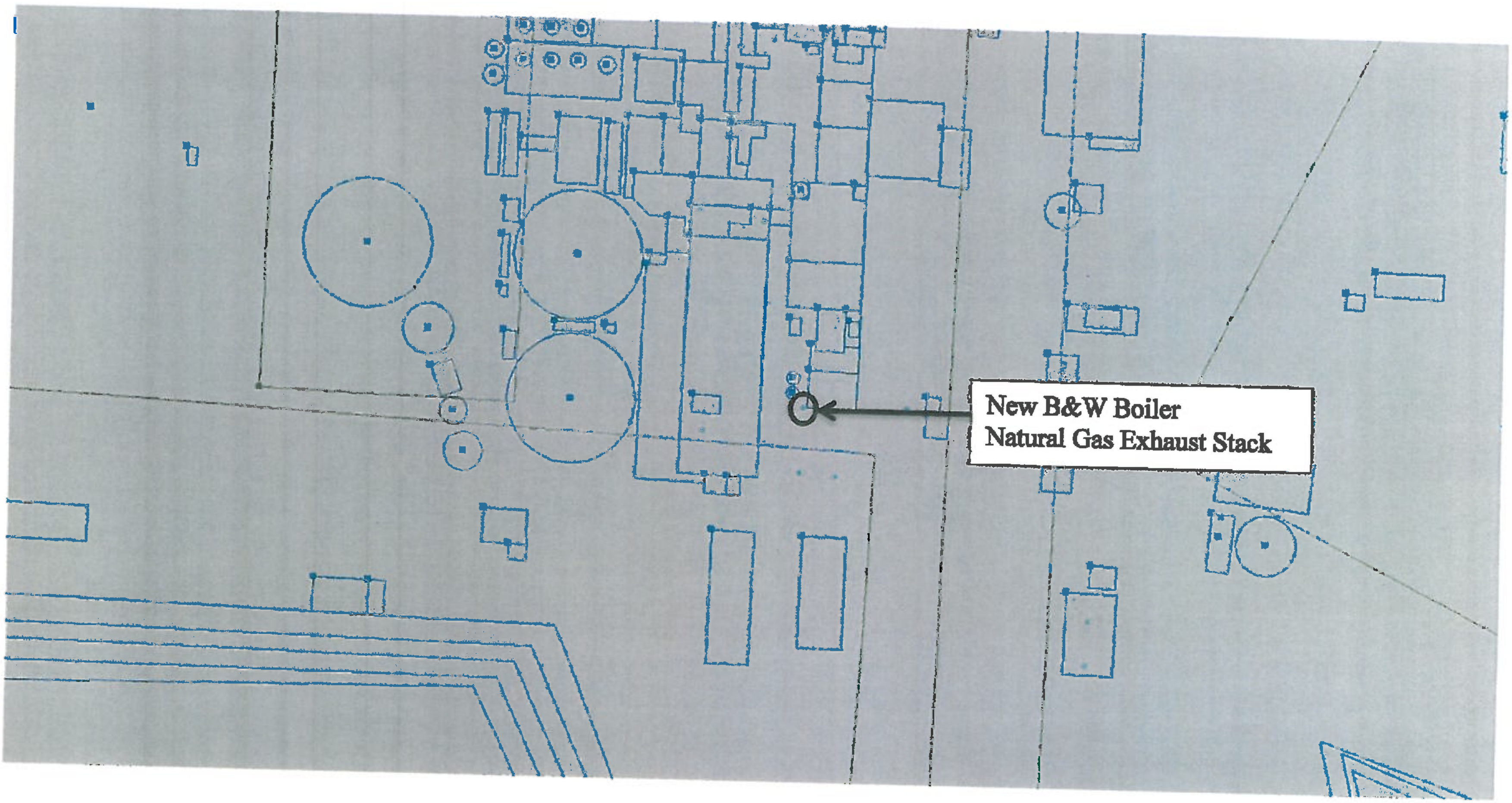

Figure 2. Fence Line and Receptor Grid

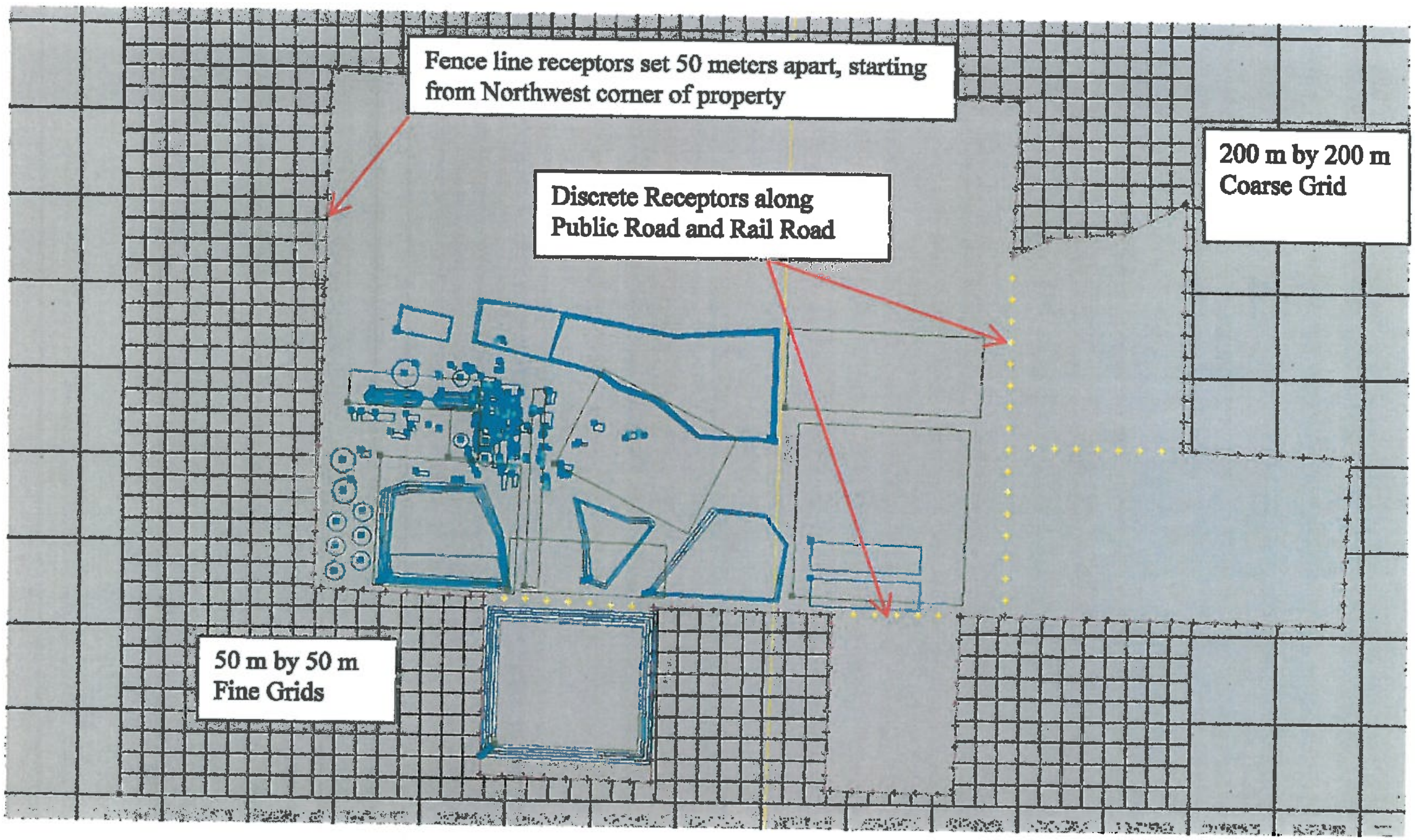

Figure 3. Location of Maximum Formaldehyde Model Predicted Concentrations