Permit to Construct No. P-2009.0136

Final

J. R. Simplot Company
Caldwell Plant
Caldwell, Idaho
Facility ID No. 027-00009

CZ
January 26, 2010
Carole Zundel
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

acfm	actual cubic feet per minute
AQCR	Air Quality Control Region
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
CAM	Compliance Assurance Monitoring
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
EPA	U.S. Environmental Protection Agency
HAP	hazardous air pollutants
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
lb/qtr	pound per quarter
m	meters
MACT	Maximum Achievable Control Technology
MMBtu/hr	million British thermal units per hour
NAAQS	National Ambient Air Quality Standard
NAICS	North American Industry Classification System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operations and maintenance
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
ppm	parts per million
PSD	Prevention of Significant Deterioration
PTC	permit to construct
PTE	potential to emit
Rules	Rules for the Control of Air Pollution in Idaho
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	sulfur dioxide
SO_X	sulfur oxides
T/yr	tons per consecutive 12-calendar month period
TAP	toxic air pollutants
UTM	Universal Transverse Mercator
VOC	volatile organic compounds

FACILITY INFORMATION

Description

The J. R. Simplot Company Caldwell facility (Simplot) produces pre-fried french fries, pre-formed and pre-fried potato products, and other processed potato products.

Permitting History

This PTC is a revision of an existing PTC and is a modification at an existing Tier I facility. See the current Tier I permit statement of basis for the permitting history.

Application Scope

The facility has applied for a permit to construct to revise PTC P-2008.0091, revised July 11, 2008.

The applicant has proposed to:

- Install and operate an additional burner in Boiler No. 1 to burn biogas with no increase in boiler capacity
- Modify the permit to remove temporary Boiler No. 11

Application Chronology

November 10, 2009	DEQ received an application
October 13, 2009	DEQ received an application fee.
November 20 – December 7, 2009	DEQ provided an opportunity to request a public comment period on the application and proposed permitting action.
December 9, 2009	DEQ made available the draft permit and statement of basis for peer and regional office review.
December 22, 2009	DEQ made available the draft permit and statement of basis for applicant review.
January 7, 2010	DEQ received a letter from the facility stating that they had no comments.
January 15, 2010	DEQ received a permit processing fee.

TECHNICAL ANALYSIS

Emissions Units and Control Devices

Table 1 EMISSIONS UNIT AND CONTROL DEVICE INFORMATION

Source Description	Emissions Controls	Emissions Discharge Point ID No. and/or Description
ADI-BVF Anaerobic Digester	Flare	
Name: Boiler No. 1 Manufacturer: English Boiler & Tube Boiler Model: 80DD325, with condensing economizer Serial No.: 28016 Manufacture Date: 2008 Fuel: Natural Gas and Biogas Max Capacity: 98.25 MMBtu/hr	Flue Gas Recirculation	B01

Emissions Inventories

Summaries of the estimated controlled emissions of criteria pollutants from the facility are provided in the following tables. An estimate of uncontrolled emissions was not necessary for this application.

The emissions from biogas combustion in the boiler were calculated using AP-42 emission factors for natural gas, except for SO_2. For calculating the SO_2 emissions, digester process data was used. It was conservatively estimated that all the H_2S would be converted to SO_2. The emissions were based on the maximum amount of biogas that can be produced. This project will not result in an increase in emissions of SO_2. The same amount of biogas may be burned before and after this project resulting in a net change of zero for SO_2 emissions. For SO_2, the only change is that the biogas may be burned in either the flare or the boiler, but the amount of gas burned and the potential emissions of SO_2 are unchanged.

Table 2 EMISSIONS ESTIMATES OF CRITERIA POLLUTANTS – CONTROLLED EMISSIONS (POTENTIAL TO EMIT)

Source	PM_{10}[c]		SO_2		NO_X		CO		VOC		Lead
	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]	lb/qtr[a]
Point Sources											
Boiler No. 1 – natural gas	0.7	3.2	0.06	0.25	4.8	21.1	8.1	35.4	0.5	2.3	None estimated
Boiler No. 1 – all biogas with natural gas	0.7	3.2	28.9	90.2	4.8	21.1	8.1	35.4	0.5	2.3	None estimated
Biogas Flare – all biogas	0.06	0.25	None estimated	90.0	0.51	2.25	2.80	12.26	1.06	4.64	None estimated
Boiler No. 8	0.60	2.64	0.05	0.21	7.92	34.70	6.65	29.15	0.44	1.91	None estimated
Line 1 Dryer Stack No. 1	3.00	13.14	0.001	0.01	0.23	1.02	0.20	0.86	0.01	0.06	None estimated
Line 1 Dryer Stack No. 2	3.00	13.14	0.001	0.01	0.23	1.02	0.20	0.86	0.01	0.06	None estimated
Line 6 Dryer Stack No. 1	2.60	11.39	0.004	0.02	0.29	1.29	0.49	2.16	0.03	0.14	None estimated
Line 6 Dryer Stack No. 2	2.60	11.39	0.004	0.02	0.29	1.29	0.49	2.16	0.03	0.14	None estimated
Line 6 Dryer Stack No. 3	2.60	11.39	0.004	0.02	0.29	1.29	0.49	2.16	0.03	0.14	None estimated
Line 6 Dryer Stack No. 4	2.60	11.39	0.004	0.02	0.29	1.29	0.49	2.16	0.03	0.14	None estimated
Air MakeUp Unit 4	0.04	0.18	0.003	0.01	0.53	2.32	0.44	1.95	0.03	0.13	None estimated
Air MakeUp Unit 5	0.08	0.33	0.01	0.03	0.99	4.35	0.83	3.65	0.05	0.24	None estimated
Air MakeUp Unit 6	0.04	0.18	0.003	0.01	0.54	2.36	0.45	1.98	0.03	0.13	None estimated
Air MakeUp Unit 7	0.04	0.18	0.003	0.01	0.54	2.38	0.46	2.00	0.03	0.13	None estimated
Air MakeUp Unit 8	0.04	0.18	0.003	0.01	0.53	2.32	0.44	1.95	0.03	0.13	None estimated
Air MakeUp Unit 9	0.04	0.18	0.003	0.01	0.53	2.32	0.44	1.95	0.03	0.13	None estimated
Air MakeUp Unit 10	0.04	0.18	0.003	0.01	0.53	2.32	0.44	1.95	0.03	0.13	None estimated
Air MakeUp Unit 11	0.04	0.18	0.003	0.01	0.54	2.36	0.45	1.98	0.03	0.13	None estimated
Air MakeUp Unit 12	0.06	0.26	0.005	0.02	0.78	3.44	0.66	2.89	0.04	0.19	None estimated
WESP	10.88	47.65	None estimated	None estimated	None estimated	None estimated	None estimated	None estimated	2.89	12.66	None estimated
Total, Point Sources	29.06	127.43	46.86	90.43	20.36	89.42	24.52	107.47	5.33	23.53	0.000
Fugitive Sources											
None											
Total, Fugitive Sources	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000

a) Controlled average emission rate in pounds per hour is a daily average

b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.
c) Particulate matter with an aerodynamic diameter less than or equal to a nominal ten (10) micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.81.

When adding the total emissions, emissions from Boiler No. 1 were not double-counted. The higher of the natural gas or natural gas and biogas was used in the total.

For toxic air pollutants (TAP), there is no change in emissions from this permitting action. No air dispersion modeling is required for TAP.

The emissions inventory for this facility is included in Appendix B.

Ambient Air Quality Impact Analyses

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 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). Although there has been no increase in emissions, the location of the release of the emissions has changed from the flare (which is still allowed) to an alternate location of the boiler. It is required that the emissions be modeled with the new emission release parameters to ensure that the emissions do not exceed any applicable ambient concentration limits.

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.

REGULATORY ANALYSIS

Attainment Designation (40 CFR 81.313)

The facility is located in Canyon 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)

The proposed project does not meet the permit to construct exemption criteria in IDAPA 58.01.01.220–223. Therefore, a permit to construct is required in accordance with IDAPA 58.01.01.201. This permitting action was processed in accordance with the procedures of IDAPA 58.01.01.200-228.

IDAPA 58.01.01.201 .... Permit to Construct Required

A permit to construct is required prior to constructing the new biogas line to the boiler in accordance with IDAPA 58.01.01 201.

The boiler will have a new nozzle installed to supply biogas to the burner. Natural gas and biogas can be burned at the same time. The boiler capacity will remain the same. The amount of fuel supplied is computer controlled.

Tier II Operating Permit (IDAPA 58.01.01.401)

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.

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

The facility is classified as a major facility, as defined in IDAPA 58.01.01.008.10. Emissions from the facility have the potential to emit greater than 100 tons per year each of PM_{10} and CO. The facility has a Tier I operating permit.

IDAPA 58.01.01.301 .... Tier I Operating Permit

This PTC is being processed in accordance with IDAPA 58.01.01.209.05.a because this PTC does not violate any terms or conditions of the existing Tier I operating permit. The information contained in this permit will be incorporated into the Tier I operating permit during renewal.

PSD Classification (40 CFR 52.21)

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)

The facility is subject to the requirements of 40 CFR 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, and 40 CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

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

40 CFR 60.40c Applicability and Delegation of Authority.

In accordance with 40 CFR 60.40c(a), Boiler No. 1 is an affected facility because it is a steam generating unit with a rated capacity of 98.25 MMBtu/hr that commenced modification after June 9, 1989. 40 CFR 60.40c(b) does not apply to the facility. 40 CFR 60.40c(c) applies to Boiler No. 1 because it meets the applicability requirements 40 CFR 60.40c(a). 40 CFR 60.40c(d) is an informational section. 40 CFR 60.40c(e) does not apply because Boiler No. 1 is not a heat recovery steam generator. 40 CFR 60.40c(f) and (g) are informational.

40 CFR 60.41c Definitions.

The definitions of this section apply to the facility.

40 CFR 60.42c Standard for Sulfur Dioxide.

40 CFR 60.42c(a) does not apply because Boiler No. 1 does not combust coal. 40 CFR 60.42c(b), (b)(1), (b)(1)(i)-(ii), (b)(2), (b)(2)(i)-(ii) do not apply because Boiler No. 1 combust neither coal, nor coal with any other fuel. 40 CFR 60.42c(c) and (c)(1) through (4) do not apply because Boiler No. 1 does not combust coal, alone or in combination with any other fuel.

40 CFR 60.42c(d) does not apply because Boiler No. 1 does not combust oil. 40 CFR 60.42c(e) does not apply because Boiler No. 1 does not combust coal, oil, or coal and oil with any other fuel. 40 CFR 60.42c(f), (f)(1), and (f)(2) do not apply because the boiler is not using coal. 40 CFR 60.42c(g) does not apply because the permittee does not combust oil. 40 CFR 60.42c(h), (h)(1) through (3) and (i) do not apply because the permittee does not combust oil or coal. 40 CFR 60.42c(j) is informational.

40 CFR 60.43c Standard for Particulate Matter.

40 CFR 60.43c(a), (a)(1), and (a)(2) do not apply because Boiler No. 1 does not combust coal or mixtures of coal with other fuels. 40 CFR 60.43c(b), (b)(1), and (b)(2) do not apply because Boiler No. 1 does not combust wood or mixtures of wood with other fuels (except coal). The opacity requirement 40 CFR 60.43c(c) does not apply because Boiler No. 1 does not combust coal, oil, or wood. 40 CFR 60.43c(d) does not apply because the opacity requirement of 40 CFR 60.43c(c) does not apply. 40 CFR 60.43c(e), e(1), (e)(2), (e)(2)(i) and (ii), (e)(3), and (e)(4) do not apply because Boiler No. 1 has a heat input capacity of 8.7 MW (30 million Btu/hr) or greater and does not combust coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

40 CFR 60.44c Compliance and Performance Test Methods and Procedures for Sulfur Dioxide.

The requirements of 40 CFR 60.44c(a) through (j) do not apply because the requirements of 60 CFR 42c do not apply and the permittee does not combust coal, oil, or coal and oil with any other fuel.

40 CFR 60.45c Compliance and Performance Test Methods and Procedures for Particulate Matter.

The requirements of 40 CFR 60.45c do not apply because the requirements of 40 CFR 60.43c do not apply.

40 CFR 60.46c Emission Monitoring for Sulfur Dioxide.

The requirements of 40 CFR 60.46c do not apply because the requirements of 40 CFR 60.42c do not apply.

40 CFR 60.47c Emission Monitoring for Sulfur Dioxide.
The requirements to install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system of 40 CFR 60.47c(a) do not apply because the particulate matter requirements of 40 CFR 60.43c do not apply. The requirements of 40 CFR 60.47c(b) do not apply because the facility does not operate of COMS. The requirement of 40 CFR 60.47c(c) does not apply because the particulate matter requirements of 40 CFR 60.43c do not apply.

40 CFR 60.48c Reporting and Recordkeeping Requirements.

40 CFR 60.48c(a), and (a)(1) apply to Boiler No. 1. 40 CFR 60.48c(a)(2) through(4) do not apply because the facility does not have any federally enforceable limits on annual capacity, nor has the facility requested to use an emerging technology to control SO_2 emissions. 40 CFR 60.48c(b) does not apply because the permittee is not subject to the SO_2 emission limits of 40 CFR 42c, the PM or opacity limits of 40 CFR 60.43c, or required to perform tests in accordance with 40 CFR 60.42c or 43c. 40 CFR 60.48c(c) does not apply because the opacity requirements 40 CFR 60.43c do not apply. The permittee is not required to report to the Administrator in accordance 40 CFR 60.48c(d) because the permittee is not subject to fuel oil sulfur limits. 40 CFR 60.48c(e) does not apply because the facility is not subject to fuel oil sulfur limits. 40 CFR 60.48c(3) through (10) do not apply because the facility is not subject to SO_2 emission limits nor does it use a CEMS.

40 CFR 60.48c(f)(1), (2), and (3) do not apply because Boiler No. 1 does not combust distillate oil, residual oil, or coal.40 CFR 48c(g), (i) and (j) generally apply. 40 CFR 48c(h) does not apply because the permittee is not subject to a limit on annual capacity.

NESHAP Applicability (40 CFR 61)

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

MACT Applicability (40 CFR 63)

The facility is not subject to any MACT standards in 40 CFR Part 63.

CAM Applicability (40 CFR 64)

The proposed source does not have a potential pre-control device emissions rate equal to or greater than 100 percent of the amount required for a source to be classified as a major source. Therefore, the proposed source is not subject to the requirements of CAM in accordance with 40 CFR 64.2(a).

Permit Conditions Review

This section describes the permit conditions for only those permit conditions that have been added, revised, modified or deleted as a result of this permitting action.

The PTC for the anaerobic digester and flare and the PTC for Boiler No. 1 have been combined in this new PTC. The permit conditions have been renumbered.

All permit conditions containing requirements for Boiler No. 11 have been modified to eliminate references to Boiler No. 11 because that boiler has been permanently removed from the facility and a permit is not longer needed.

All permit conditions which reference other permit conditions or general provisions in the text of the condition have been rewritten to eliminate the numerical permit condition reference.

The chemical oxygen demand (COD) reduction can be correlated to the H_2S concentration and SO_2 emissions. Performance testing has been done and demonstrated compliance with the H_2S limit. H_2S concentrations can be used to calculate SO_2 emissions as is done in the emission inventory of the permit application. The COD reduction limit and monitoring can be replaced with monitoring the biogas flow rate.

J. R. Simplot Company owns a potato plant in Aberdeen that utilizes an anaerobic digester. An H_2S monitor was used to monitor H_2S concentrations at the digester at that plant, and testing was done in addition to correlate monitored H_2S and tested H_2S concentrations. The tested H_2S concentration for Aberdeen was 2300 dry ppm at 45.03 scfm. The test was conducted on July 25, 2006. The monitored H_2S concentration for July 2006 was 2478 ppm and a flow rate of 47.5 scfm. The tested value is similar to the monitored value. Therefore, the monitored values have been determined to be representative of actual concentrations.

The monitored values from November 2005 through December 2007 at the Aberdeen plant range from a concentration of 1493 ppm to 4275 ppm. There does not seem to be a clear correlation between concentration and biogas flow rate.

The facility sent H_2S monitoring results to DEQ on January 10, 2010. The results are different than the monitoring results sent in on December 7, 2009. According to the facility in an e-mail dated January 15, 2010, regarding the historical collection of hydrogen sulfide data at the anaerobic digester at the Aberdeen facility, the facility's assessment of the monthly vs. the weekly data is that the Drager data was actually reported to two decimal places, but it appeared on the spreadsheet as one decimal place.

According to the facility, the drager testing does appear very close to the reading of the Ultima monitor because the drager sample was taken from the same location where the Ultima monitor took its sample, after a 100 to 1 dilution of the sample, to get in the range of both the drager tubes and the monitor detection range (generally 0-100 ppm).

The data range for the monitored H_2S concentrations in the biogas was between 0.03% and 0.58%.

There were two tests done on the digester at the Caldwell facility. The first was done on December 20, 2000 with a concentration of 2500 ppm H_2S. The second test was done on November 18, 2003, with a concentration of 2183 ppm.

The existing H_2S limit is 5,391 ppmv. The two tests done on the digester were approximately half of the limit. The emissions estimation for this permit application was done using the H_2S limit and the maximum biogas flowrate of 529 scfm. This emission rate showed compliance with the SO_2 NAAQS. In order to ensure that the estimated emissions are not exceeded, a limit of 529 scfm has been written as a permit condition, as follows:

New Permit Condition

Hydrogen Sulfide Flowrate Limit

The biogas flowate shall not exceed a maximum of 529 standard cubic feet per minute.

Monitoring is required, which will measure actual cubic feet per minute, and a requirement is written to convert this monitored value to standard cubic feet per minute for comparison to the limit. To do the conversion, monitoring of the pressure and temperature will be required. These parameters are likely already being monitored. A permit condition was written as follows:

New Permit Condition

Biogas Flow Monitoring

The permittee shall install, calibrate, maintain, and operate a biogas flowmeter to measure the biogas being burned at the flare and Boiler No. 1 from the anaerobic digester. The biogas flowrate shall be monitored continuously and averaged and recorded once per hour. The actual cubic feet per minute (acfm) flow values measured shall be converted to standard cubic feet per minute to compare to the biogas flowrate limit in this permit.

This approach replaces the previous approach of monitoring the COD. As soon as this method is operational, the COD monitoring can be discontinued for PTC compliance purposes. The monitoring is still required by the facility's Tier I operating permit until that permit is updated.

Previous Permit Condition

Chemical Oxygen Demand Reduction Limit

The COD reduction of the wastewater in the ADI-BVF digester shall be limited to an average of 2,000,000 pounds per month during any 12-month period.

Revised Permit Condition

Chemical Oxygen Demand Reduction Limit

The COD reduction of the wastewater in the ADI-BVF digester shall be limited to an average of 2,000,000 pounds per month during any 12-month period. This permit limit shall expire upon initiation of the monitoring of the biogas flow rate to the flare and Boiler No. 1.

Previous Permit Condition

Chemical Oxygen Demand Reduction Monitoring

The COD reduced in the ADI-BVF digester shall be monitored and recorded, at a minimum, on a monthly basis. Monthly values shall be used to calculated the 12-month averages. A compilation of the most recent two years of records shall be kept onsite and shall be made available to DEQ representatives upon request.

Revised Permit Condition

Chemical Oxygen Demand Reduction Monitoring

The COD reduced in the ADI-BVF digester shall be monitored and recorded, at a minimum, on a monthly basis. Monthly values shall be used to calculated the 12-month averages. A compilation of the most recent two years of records shall be kept onsite and shall be made available to DEQ representatives upon request. This permit limit shall expire upon initiation of the monitoring of the biogas flow rate to the flare and Boiler No. 1.

Revised Permit Condition

Emission Limits

The total SO_2 emissions from the combustion of biogas from the ADI-BVF digester flare stack and the No. 1 boiler shall not exceed 90.0 tons per any consecutive 12-month period.

The annual emission rate has not changed, but now the total emissions are allowed to be emitted from Boiler No. 1 as well as the flare.

Removed Permit Conditions

The testing requirement was taken out of the permit because the required testing has been done, and any subsequent tests are already regulated by the general provisions in this permit.

The history of the biogas operation is as follows (from e-mail from J. R. Simplot Company, dated January 15, 2010) :

Spring 1997	Started construction on digester

September 5, 1997	Start of construction of the flare
Fall 1997	Digester completed and start to fill & seed
December 1997	Digester ready for startup phase
December 17, 1997	Biogas flare PTC issued
December 24, 1997	Lining failure in digester, shut digester down, flare never operated
Spring & Summer 1998	Repair liner in digester
Fall 1998	Start up digester, flare never operated
December 1998	Lining failure again in digester, shut digester down
Summer & Fall 1999	Re-construct digester
November 25, 1999	Construction completed
December 8, 1999	Digester started up
April 22, 2000	PTC application for minor revisions to 1997 PTC
Spring & Summer, 2000	Startup continued, flare started up
October 27, 2000	Request for source test extension by Simplot
December 20, 2000	Source testing conducted on biogas flare
February 8, 2001	Source test approved by DEQ
December 10, 2001	PTC re-issued for minor revisions. It was the intent of Simplot for the December 20, 2000 source test to apply for the re-issued PTC (application submitted on April 22, 2000), but because of the delay in re-issue (as documented in the technical memorandum for that PTC), the source test was completed prior to the re-issue date.
October 17, 2003	PTC re-issued again based on minor modifications from an appeal & settlement of the Caldwell facility Tier I permit. This permit required another source test.
November 18, 2003	Source test conducted on biogas flare
June 30, 2004	Source test approved by DEQ

Because this test was done, the requirement to do this test was removed from this current permit action.

Hydrogen Sulfide Performance Test

Within 120 days of issuance of PTC No. 027-00009, dated December 10, 2001, the permittee shall have conducted a performance test to measure the H2S concentration in the biogas prior to the biogas flare. The performance test and any subsequent performance tests conducted to demonstrate compliance with the hydrogen sulfide concentration limit shall be performed in accordance with IDAPA 58.01.01.157 and the performance testing requirements specified in the general provisions of this permit.

Performance Test Protocol

The permittee shall submit a test protocol for the performance test required in the hydrogen sulfide performance test permit condition of this permit to DEQ for approval at least 30 days prior to the test days.

Removed Permit Condition

The permittee shall submit a report of the results of the compliance test required in Permit Condition 2.11 of this permit, including all required process data, to DEQ within 30 days after the date on which the performance test is concluded.

This permit condition requiring the compliance test for H_2S to be submitted to DEQ within 30 days was removed because performance test reports are required in the general provisions.

Removed Permit Condition

All documents submitted to DEQ shall comply with General Provision 8 of this permit.

This permit condition was removed because it is in the general provisions.

PUBLIC REVIEW

Public Comment Opportunity

An opportunity for public comment period on the application was provided in accordance with IDAPA 58.01.01.209.01.c. During this time, there were no comments on the application and there was not a request for a public comment period on DEQ's proposed action. Refer to the chronology for public comment opportunity dates.

APPENDIX A – EMISSIONS INVENTORIES

Caldwell Plant Potential to Emit (TPY)[(a)]

	Boiler 8	Boiler 1 - NG Comb	Boiler 1 - Biogas & NG Comb [(b)]	Biogas Flare[(b)]	Dryer 1	Dryer 6	WESP[(d)]	AMUs	Solvent and Adhesive Use [(e)]	Total Emissions	Hazardous Air Pollutant?	Total HAP Emissions
Criteria Air Pollutants												
PM10	2.6	3.2	3.2	0.2	26.3	45.6	47.7	1.8	-	127.4	No	-
NOx	34.7	21.1	21.1	2.3	2.0	5.2	-	24.2	-	89.4	No	-
SO2[(b)]	0.2	0.3	90.2 (90 tpy limit on biogas comb.)		0.01	0.06	-	0.1	-	90.6	No	-
CO	29.1	35.4	35.4	12.3	1.7	8.7	-	20.3	-	107.5	No	-
VOC	1.9	2.3	2.3	4.6	0.1	0.6	12.7	1.3	2.8	26.3	No	-
Toxic Air Pollutants												
3-Methylchloranthrene	6.2E-07	7.6E-07	7.6E-07	-	3.7E-08	1.9E-07	-	4.3E-07	-	2.0E-06	No	-
Ammonia	1.1E+00	1.4E+00	1.4E+00	-	6.5E-02	3.3E-01	-	-	-	2.9	No	-
Benzene	7.3E-04	8.9E-04	8.9E-04	-	4.3E-05	2.2E-04	-	5.1E-04	-	2.4E-03	Yes	2.4E-03
Benzo(a)pyrene	4.2E-07	5.1E-07	5.1E-07	-	2.4E-08	1.2E-07	-	2.9E-07	-	1.4E-06	No	-
Dichlorobenzene	4.2E-04	5.1E-04	5.1E-04	-	2.4E-05	1.2E-04	-	2.9E-04	-	1.4E-03	No	-
Formaldehyde	2.6E-02	3.2E-02	3.2E-02	-	1.5E-03	7.7E-03	-	1.8E-02	-	8.5E-02	Yes	8.5E-02
Hexane	6.2E-01	7.6E-01	7.6E-01	-	3.7E-02	1.9E-01	-	4.3E-01	-	2.0	Yes	2.0
Naphthalene	2.1E-04	2.6E-04	2.6E-04	-	1.2E-05	6.3E-05	-	1.5E-04	-	6.9E-04	Yes	6.9E-04
Pentane	9.0E-01	1.1E+00	1.1E+00	-	5.3E-02	2.7E-01	-	6.3E-01	-	2.9	No	-
Toluene	1.2E-03	1.4E-03	1.4E-03	-	6.9E-05	3.5E-04	-	8.2E-04	-	3.9E-03	Yes	3.9E-03
Arsenic	6.9E-05	8.4E-05	8.4E-05	-	4.1E-06	2.1E-05	-	4.8E-05	-	2.3E-04	Yes	2.3E-04
Barium	1.5E-03	1.9E-03	1.9E-03	-	9.0E-05	4.5E-04	-	1.1E-03	-	5.0E-03	No	-
Beryllium	4.2E-06	5.1E-06	5.1E-06	-	2.4E-07	1.2E-06	-	2.9E-06	-	1.4E-05	Yes	1.4E-05
Cadmium	3.8E-04	4.6E-04	4.6E-04	-	2.2E-05	1.1E-04	-	2.7E-04	-	1.2E-03	Yes	1.2E-03
Chromium-Total[(c)]	4.9E-04	5.9E-04	5.9E-04	-	2.9E-05	1.4E-04	-	3.4E-04	-	1.6E-03	Yes	1.6E-03
Chromium III	4.0E-04	4.8E-04	4.8E-04	-	2.3E-05	1.2E-04	-	2.8E-04	-	1.3E-03	-	-
Chromium VI	8.7E-05	4.0E-04	4.0E-04	-	5.1E-06	2.6E-05	-	6.1E-05	-	5.8E-04	-	-
Cobalt	2.9E-05	3.5E-05	3.5E-05	-	1.7E-06	8.7E-06	-	2.0E-05	-	9.5E-05	Yes	9.5E-05
Copper	2.9E-04	3.6E-04	3.6E-04	-	1.7E-05	8.8E-05	-	2.1E-04	-	9.6E-04	No	-
Manganese	1.3E-04	1.6E-04	1.6E-04	-	7.8E-06	3.9E-05	-	9.2E-05	-	4.3E-04	Yes	4.3E-04
Mercury	9.0E-05	1.1E-04	1.1E-04	-	5.3E-06	2.7E-05	-	6.3E-05	-	2.9E-04	Yes	2.9E-04
Molybdenum	3.8E-04	4.6E-04	4.6E-04	-	2.2E-05	1.1E-04	-	2.7E-04	-	1.2E-03	No	-
Nickel	7.3E-04	8.9E-04	8.9E-04	-	4.3E-05	2.2E-04	-	5.1E-04	-	2.4E-03	Yes	2.4E-03
Selenium	8.3E-06	1.0E-05	1.0E-05	-	4.9E-07	2.5E-06	-	5.8E-06	-	2.7E-05	Yes	2.7E-05
Zinc	1.0E-02	1.2E-02	1.2E-02	-	5.9E-04	3.0E-03	-	7.0E-03	-	3.3E-02	No	-
Nitrous Oxide	7.6E-01	9.3E-01	9.3E-01	-	4.5E-02	2.3E-01	-	5.3E-01	-	2.5	No	-
Polyaromatic Hydrocarbons (a subset of Toxic Air Pollutants)												
Benz(a)anthracene	6.2E-07	7.6E-07	7.6E-07	-	3.7E-08	1.9E-07	-	4.3E-07	-	2.0E-06	No	-
Benzo(a)pyrene	4.2E-07	5.1E-07	5.1E-07	-	2.4E-08	1.2E-07	-	2.9E-07	-	1.4E-06	No	-
Benzo(b)fluoranthene	6.2E-07	7.6E-07	7.6E-07	-	3.7E-08	1.9E-07	-	4.3E-07	-	2.0E-06	No	-
Benzo(k)fluoranthene	6.2E-07	7.6E-07	7.6E-07	-	3.7E-08	1.9E-07	-	4.3E-07	-	2.0E-06	No	-
Chrysene	6.2E-07	7.6E-07	7.6E-07	-	3.7E-08	1.9E-07	-	4.3E-07	-	2.0E-06	No	-
Dibenzo(a,h)anthrancene	4.2E-07	5.1E-07	5.1E-07	-	2.4E-08	1.2E-07	-	2.9E-07	-	1.4E-06	No	-
Indeno(1,2,3-cd)pyrene	6.2E-07	7.6E-07	7.6E-07	-	3.7E-08	1.9E-07	-	4.3E-07	-	2.0E-06	No	-
PAH Total	*4.0E-06*	*4.8E-06*	*4.8E-06*	-	*2.3E-07*	*1.2E-06*	-	*2.8E-06*	-	10.5	Total HAPs	2.1

Shaded values are emission limits established in prior permits.

(a) This summary table is intended for informational purposes only. The J.R. Simplot Company is not proposing annual emission limits. Annual emissions were based on 8760 hours of operation at the short-term emission rate, except for the annual SO2 emissions from the biogas flare. A permit condition limits SO2 emissions from the biogas flare to 90 TPY.

(b) As proposed in this PTC application, Boiler No.1 and the biogas flare will be capable of combusting biogas generated by the facility's anaerobic digester. Each source is capable of firing all generated biogas on an hourly and annual basis, or the biogas can be split between each source. Please note, biogas combustion emissions are limited to 90 tons SO2/year. However Boiler No.1 can combust the maximum amount of biogas generated plus some additional natural gas, resulting in Boiler No.1 SO2 PTE of 90.2 tons/yr (additional 0.2 tons/yr from natural gas combustion).

(c) AP-42 provides a chromium emission factor for natural gas fired external combustion, but does not include guidance for partitioning emissions between the carcinogenic chromium VI (hexavalent chromium) and the chromium III (trivalent chromium). In the EPA's Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress (EPA-453/R-98-004a), chromium emissions from natural gas-fired units are not included. However, data on speciation of chromium were available from 11 coal- and oil-fired test sites. From these limited data, EPA estimated that the average chromium VI from the coal-fired utilities was 11 percent, and the average from oil-fired utilities was 18 percent. We have conservatively assumed 18 percent of the chromium emissions are chromium VI.

(d) The PM10 emission estimates presented here are from all three fryers. However, as an emission limit this value applies only to the Line 1 fryer.

(e) Additional information regarding the emission calculations for these sources is included in the Caldwell facility's 1995 Tier I Operating Permit application.

BOILER 1 WITH BIOGAS BURNER

Total Boiler Heat Input Capacity	98.25	MMBtu/hr
Maximum Nat'l gas Fuel Usage*	0.096	MMscf/hr

*(based on 1020 Btu/scf) and
8,760 Permitted Hours of Operation/yr

With Addition of Maximum Biogas Combustion Capacity to the boiler:

	Short-term (hourly at peak)	Long-Term (annual maximum)
Fraction from Nat'l gas	80.62%	86.19%
scf biogas/averaging time	31,740	198,092,842
MMBtu/averaging time	19.0	118,856

Biogas parameters:
600 Btu/scf, HHV biogas
0.6 methane, fraction CH4 of biogas

Pollutant	Emission Factor (lb/MMBtu)[a]	Potential to Emit		Project Increase		Modeling De Minimus Thresholds [b]		Over Modeling Threshold?
		lb/hr	TPY	lb/hr	TPY	(lb/hr)	(TPY)	
NOx	0.049	4.8	21.1	0.00	0.00	--	1	No
CO	0.082	8.1	35.4	0.00	0.00	14	--	No
SO2 [c]	--	28.9	90.2	28.8	90	0.2	1	Yes
PM-10	0.0075	0.7	3.2	0.00	0.00	0.2	1	No
VOC	0.0054	0.5	2.3	0.00	0.00	--	--	No

Pollutant	CAS No.	Emission Factor (lb/MMBtu)[a]	lb/hr	lb/yr [g]
Arsenic	7440-38-2	2.0E-07	1.93E-05	1.69E-01
Barium	7440-39-3	4.3E-06	4.24E-04	3.71E+00
Benzene	71-43-2	2.1E-06	2.02E-04	1.77E+00
Beryllium	7440-41-7	1.2E-08	1.16E-06	1.01E-02
Cadmium	7440-43-9	1.1E-06	1.06E-04	9.28E-01
Chromium-Total[d]	7440-47-3	1.4E-06	1.35E-04	1.18E+00
Chromium III	7440-47-3	1.1E-06	1.11E-04	9.69E-01
Chromium VI	C7440-47-3	9.2E-07	9.07E-05	7.94E-01
Cobalt	7440-48-4	8.2E-08	8.09E-06	7.09E-02
Copper	7440-50-8	8.3E-07	8.19E-05	7.17E-01
Formaldehyde	50-00-0	7.4E-05	7.22E-03	6.33E+01
Hexane	110-54-3	1.8E-03	1.73E-01	1.52E+03
Manganese	7439-96-5	3.7E-07	3.66E-05	3.21E-01
Mercury	7439-97-6	2.5E-07	2.50E-05	2.19E-01
Molybdenum	7439-98-7	1.1E-06	1.06E-04	9.28E-01
Naphthalene	91-20-3	6.0E-07	5.88E-05	5.15E-01
Nickel	7440-02-0	2.1E-06	2.02E-04	1.77E+00
Pentane	109-66-0	2.5E-03	2.50E-01	2.19E+03
Selenium	7782-49-2	2.4E-08	2.31E-06	2.03E-02
Toluene	108-88-3	3.3E-06	3.28E-04	2.87E+00
Nitrous Oxide	10024-97-2	2.2E-03	2.12E-01	1.86E+03
Benz(a)anthracene	56-55-3	1.8E-09	1.73E-07	1.52E-03
Benzo(a)pyrene	50-32-8	1.2E-09	1.16E-07	1.01E-03
Benzo(b)fluoranthene	205-99-2	1.8E-09	1.73E-07	1.52E-03
Benzo(k)fluoranthene	207-08-9	1.8E-09	1.73E-07	1.52E-03
Chrysene	218-01-9	1.8E-09	1.73E-07	1.52E-03
Dibenzo(a,h)anthracene	53-70-3	1.2E-09	1.16E-07	1.01E-03
Indeno(1,2,3-cd)pyrene	193-39-5	1.8E-09	1.73E-07	1.52E-03
3-Methylchloranthrene	91-57-6	1.8E-09	1.73E-07	1.52E-03
Dichlorobenzene	23521-22-6	1.2E-06	1.16E-04	1.01E+00
Zinc	7440-66-6	2.8E-05	2.79E-03	2.45E+01
Ammonia[e]	7664-41-7	3.1E-03	3.08E-01	2.70E+03
PAH (total)[f]	-	-	1.10E-06	9.82E-03

(a) Emission Factors from AP-42 Section 1.4, *Natural Gas Combustion*, July 1998. Converted to lb/MMBtu using 1020 Btu/cf natural gas.

(b) Modeling thresholds from Table 1 of the State of Idaho Air Quality Modeling Guideline (Doc. I D AQ-011 (rev. 1 12/31/02)).

(c) SO2 emissions based on firing combination of biogas (1,514 lb/MMscf methane) and natural gas (0.6 lb/MMscf natural gas).

(d) AP-42 provides a chromium emission factor for natural gas fired external combustion, but does not include guidance for partitioning emissions between the carcinogenic chromium VI (hexavalent chromium) and the chromium III (trivalent chromium). In the EPA's Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units -- Final Report to Congress (EPA-453/R-98-004a), chromium emissions from natural gas-fired units are not included. However, data on speciation of chromium were available from 11 coal- and oil-fired test sites. From these limited data, EPA estimated that the average chromium VI from the coal-fired utilities was 11 percent, and the average from oil-fired utilities was 18 percent. We have conservatively assumed 18 percent of the chromium emissions are chromium VI.

(e) Ammonia emission factor from EPA's WebFIRE database (http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main)

(f) (Polycyclic Organic Matter) For emissions of PAH mixtures, the following PAHs and shall be considered together as one TAP, equivalent in potency to benzo(a)pyrene: benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, dibenzo(a,h)anthracene, chrysene, indeno(1,2,3,-cd)pyrene, benzo(a)pyrene. (WA)

(g) Assume 8,760 hours of operation per year.

Sulfur Dioxide Calculations - Maximum Day Emissions

Basis:	31,740	scf/hr	Biogas (based on maximum blower throughput of 500 scfm with 29 scfm safety factor)
	19,044	scf/hr	Methane @ 60% methane (PTC analysis)
	5391	ppmv	Hydrogen Sulfide in Biogas (Digester Permit Limit)

Calculation: at 5391 ppmv H2S in Biogas = 0.005391 volume fraction of total Biogas

171.11034 scf H2S/hr

(31,740 scf/hr) x (0.005391) = 171 scf H2S/hr

PV = nRT

1 P = pressure, atmospheres

171.11034 V = volume, cubic feet

n = lbmoles

0.7302 R = gas constant, atm-cf/lbmoles-deg. R

520 T = temperature, deg. R

For standard pressure and temperature (STP)
T = 32 deg. F, 0 deg. C, 492 deg. R
P = 1 atm.

$$n = \frac{PV}{RT} = \frac{(1\text{ atm})\ (171.1\text{ scf H2S/hr})}{(0.7302\text{ atm-cf/lbmoles-deg. R})\ (460+60\text{ deg. R})}$$

= 0.4506414 lbmoles H2S/hr

	H_2S	+	$1\frac{1}{2}O_2$	g	SO_2	+	H_2O
MW	34				64		
lbmoles/hr	0.4506414				0.4506414		
lbs/hr	15.321807				28.841049		

Emission Factor for sulfur dioxide

$$\frac{(28.8\text{ lbs SO2/hr})\ (1{,}000{,}000)}{(19{,}044\text{ scf CH4/hr})\ (\quad\text{MM}\quad)} = 1514.4\text{ lbs SO2/MM scf CH4}$$

Sulfur Dioxide Calculations - Average Day/Annual Emissions

Basis:	23,771,141 COD reduced/yr	Biogas PTC Application (1999)
	542,720 scf biogas/day	Biogas (based on COD reduction, 5.0 cf methane/lb COD reduced) - average annual flow rate from 1997 flare PTC Application
	325,632 scf CH4/day	Methane @ 60% methane (PTC analysis)
	5 cf CH4/lb COD redu	PTC analysis
Digester and Flare Permit Limits:	2000000 lb COD/month	
	90 tons SO2/year	
	5391 ppmv	Hydrogen Sulfide in Biogas (Digester Permit Limit)

Calculation:

at 5391 ppmv H2S in Biogas = 0.005391 volume fraction of total Biogas
(542,720 scf/day) x (0.005391) = 2,926 scf H2S/day
2926 scf H2S/day

PV = nRT
1 P = pressure, atmospheres
2925.8 V = volume, cubic feet
n = lbmoles
0.7302 R = gas constant, atm-cf/lbmoles-deg. R
520 T = temperature, deg. R

For standard pressure and temperature (STP)
T = 32 deg. F, 0 deg. C, 492 deg. R
P = 1 atm.

$$n = \frac{PV}{RT} = \frac{(1\ \text{atm})(2{,}925.8\ \text{scf H2S/day})}{(0.7302\ \text{atm-cf/lbmoles-deg. R})(460+60\ \text{deg. R})}$$

= 7.71 lbmoles H2S/day

	H_2S	+	$1½O_2$	g	SO_2	+	H_2O
MW	34				64		
lbmoles/d	7.7				7.7		
lbs/day	262.0				493.2		

493.15115 lbs/day x 365 days = 180,000 lbs/yr SO_2

= 90.0 tons/yr SO_2

Emission Factor for sulfur dioxide

$$\frac{(493.2\ \text{lbs SO2/d})(1{,}000{,}000)}{(325{,}632\ \text{scf CH4/d})(\ \text{MM}\ )} = 1514.4\ \text{lbs SO2/MM scf CH4}$$

APPENDIX B – PERMIT FEES

PTC Fee Calculation

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: **J. R. Simplot Company, Caldwell**
Address: **P. O. Box 1059**
City: **Caldwell**
State: **Idaho**
Zip Code: **83606**
Facility Contact: **Lance Carter**
Title: **Environmental Manager**
AIRS No.: **027-00009**

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	0	0.0
SO_2	0.0	0	0.0
CO	0.0	0	0.0
PM10	0.0	0	0.0
VOC	0.0	0	0.0
TAPS/HAPS	0.0	0	0.0
Total:	0.0	0	**0.0**
Fee Due	$ 1,000.00		

Comments: