United States Environmental Protection Agency
Region 8
Air Program
1595 Wynkoop Street
Denver, Colorado 80202-1129
December 12, 2013

Air Pollution Control
Prevention of Significant Deterioration (PSD)
Permit to Construct

PSD-WY-000004-2012.001

Permittee:
Solvay Soda Ash Joint Venture
Green River Soda Ash Plant
P. O. Box 1167
Green River, WY 82935

Permitted Facility:
Green River Soda Ash Plant Green River, Wyoming

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Table of Acronyms

BACT	Best Available Control Technology
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalent
EP	Emission Point
FIP	Federal Implementation Plan
FR	Federal Register
GHG	Greenhouse Gas
hr	Hour
lb	Pound
lbpy	Pounds Per Year
Mscf	Million Standard Cubic Foot
N_2O	Nitrous Oxide
NSPS	New Source Performance Standards
NO_x	Nitrogen Oxides
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
QA/QC	Quality Assurance and/or Quality Control
SF_6	Sulfur Hexafluoride
tpy	Tons Per Year
VOC	Volatile Organic Compounds
%	Percent

I. INTRODUCTION

This Federal Prevention of Significant Deterioration (PSD) permit is being issued under authority of 40 CFR 52.21 (PSD) and 52.37 (Federal Implementation Plan (FIP) to issue permits under the PSD requirements to sources that emit greenhouse gases (GHGs). Green River Soda Ash Plant (hereinafter the "Permittee" or "Solvay") proposes to construct a new natural gas fired boiler that will add steam-generating capacity to the Solvay facility. The addition of this natural gas fired boiler with the two existing coal-fueled boilers will allow Solvay the operational flexibility to (1) shut any one of the three boilers down for maintenance without curtailing production, and (2) take advantage of the lower-cost fuel (coal vs. natural gas).

With this project, Solvay expects to increase annual soda ash production by approximately 14 percent. This permit modification assumes no operational limit on combined steam production, and the additional boiler will be permitted to operate at capacity. In this way, the gas-fueled boiler could run at its maximum while the coal boilers would supplement as needed, or the coal-fueled boilers could operate at their capacity while the gas boiler would supplement the steam demand.

This additional boiler is a water tube package boiler natural gas fired (a Foster Wheeler Model AG 5195, 254 MMBtu/hr boiler) that was installed previously in Garfield County, Colorado at the American Soda facility. It was used from 2000 through May 2004 and then permanently shut down. It is a boiler capable of producing 200,000 lbs. of steam per hour, to be added in parallel to the two 300,000 lbs. per hour coal boilers. In 2003, Solvay purchased the American Soda facility in Garfield County, Colorado, including the Foster Wheeler Model AG 5195 natural gas fired boiler. The boiler will be fueled through the Western Gas Pipeline by a spur currently feeding the Solvay plant.

II. GENERAL PERMIT CONDITIONS

On the basis of findings set forth in Section III, Special Permit Conditions, of this permit, and pursuant to the authority (as delegated by the Administrator) at 52.37, EPA hereby authorizes Solvay to construct or modify the natural gas fired boiler. The authorization is expressly conditioned as follows:

A. PERMIT EFFECTIVE DATE AND EXPIRATION

As provided in 40 CFR 124.15(b), this PSD permit shall become effective 30 days after the service of notice of the permit decision, unless:

1. a later effective date is specified in the decision;

2. review is requested on the permit under 40 CFR 124.19; or

3. no comments requested a change in the draft permit, in which case the permit shall become effective immediately upon issuance.

As provided in 40 CFR 52.21(r)(2), this PSD permit shall become invalid if construction:

1. is not commenced (as defined in 40 CFR 52.21(b)(9)) within 18 months after the approval takes effect; or

2. is discontinued for a period of 18 months or more; or

3. is not completed within a reasonable time.

Under 40 CFR 52.21(r)(2), EPA may extend the 18 month period upon a satisfactory showing that an extension is justified.

B. PERMIT NOTIFICATION REQUIREMENTS

The Permittee shall notify EPA in writing of:

1. the date construction is commenced, postmarked within 30 days of such date;

2. the actual date of initial startup, postmarked within 15 days of such date. Startup is defined as the setting in operation of an affected facility for any purpose;

3. the date upon which initial performance tests will commence, in accordance with the provisions of Section V., Performance Testing Requirements, of this permit, postmarked not less than 30 days prior to such date; and

4. other events as required elsewhere in this permit.

C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and malfunction, Permittee shall maintain and operate the facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing GHG emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA, which may include, but is not limited to, monitoring results, review of operating maintenance procedures and inspection of the facility.

D. MALFUNCTION REPORTING

1. The Permittee shall notify EPA by mail within 2 working days following the discovery of any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner, which results in an increase in CO_{2e} emissions above the allowable emission limits stated in Condition III.A. Point Source Emission Limits, of this permit.

2. In addition, the Permittee shall notify EPA in writing within 15 calendar days of any such failure described under Section IV. Recordkeeping Requirements. This notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Condition III.A. Point Source Emission Limits, and the methods utilized to mitigate emissions and restore normal operations.

3. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

E. RIGHT OF ENTRY

EPA authorized representatives, upon the presentation of credentials, shall be permitted:

1. to enter the premises where the facility is located or where any records are required to be kept under the terms and conditions of this PSD Permit;

2. during normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD Permit;

3. to inspect any equipment, operation, or method subject to requirements in this PSD Permit; and,

4. to sample materials and emissions from the source(s).

F. TRANSFER OF OWNERSHIP

In the event of any changes in control or ownership of the facilities to be constructed under this PSD permit, this PSD permit is binding on all subsequent owners and operators. The Permittee shall notify, by letter, the succeeding owner and operator of the existence of this PSD permit and its conditions. A copy of the letter shall be provided to EPA within 30 days of the letter signature. Permit transfers shall be made in accordance with 40 CFR Part 122, Subpart D.

G. SEVERABILITY

The provisions of this PSD permit are severable, and, if any provision of the PSD permit is held invalid, the remainder of this PSD permit shall not be affected.

H. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

The Permittee shall construct and operate this project in compliance with this PSD permit, the application on which this PSD permit is based, and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

I. BINDING APPLICATION

This permit is issued in reliance upon the accuracy and completeness of the information set forth in the Permittee's application to EPA dated August 2012, and subsequent information provided by the Permittee to EPA, as listed in the Administrative Record for issuance of this permit.

The Permittee shall abide by all representations, statements of intent and agreements contained in the permit application and subsequent submittals as listed in the Administrative Record. EPA shall be notified no less than 10 working days in advance of any significant deviation from the permit application, and shall furnish any plans, specifications or supporting data regarding such deviation. The issuance of this PSD permit to Construct and Operate may be suspended or revoked if EPA determines that a significant deviation from the permit application, specifications, and supporting data furnished has been, or is to be, made.

J. ENFORCEABILITY OF PERMIT

On the effective date of this permit, the conditions herein become enforceable by EPA pursuant to any remedies it now has or may have in the future, under the Clean Air Act.

K. TREATMENT OF EMISSIONS

Emissions in excess of the limits specified in this permit shall constitute a violation.

III. SPECIAL PERMIT CONDITIONS

A. POINT SOURCE EMISSION LIMITS

At all times after completion of the installation of the natural gas fired boiler, including during startup, shutdown and malfunction, the Permittee shall not allow the discharge of GHG emissions from the unit into the atmosphere, in excess of the following:

Table 1: Emission Limits

Emission Point/Equipment	Limitations
Foster Wheeler Model AG 5195, 254 MMBtu/hr natural gas fired boiler	• 125.3lb per MMBtu based on a 24 hour rolling average • 130,263 ton CO_{2e} /365 day based on 365-day rolling average

B. REQUIREMENTS FOR NATURAL GAS FIRED BOILER

1. Compliance with lb CO_{2e} /MMBtu BACT Emission Limit

The above listed emission unit shall demonstrate compliance with the lb CO_{2e}/MMBTu BACT emission limit by the following equation:

Equation 1

$$CO2 \geq (5.18\, x 10^{-7}\, x\, C_{CO2}\, x\, Q\, x\, 2204.62) \div (V_{Hi}\, x\, 1020)$$

Where:

$CO2$ =	24 hour rolling average limit in Special Condition III.A,
C_{CO2} =	Hourly average CO_2 concentration (% CO_2)
Q =	Hourly average stack gas volumetric flow rate (scfh)
$5.18\, x 10^{-7}$ =	Conversion factor (metric tons/scf/% CO_2)
2204.62 =	Conversion factor (lbs/metric tons)
1020 =	Conversion factor (MMBtu/Mscf)
V_{Hi} =	Hourly volumetric flow rate of natural gas to the boiler (Mscf)

2. Compliance with ton CO_{2e} / 365 day BACT Emission Limit

The above listed emission unit shall demonstrate compliance with the ton CO_{2e}/yr BACT emission limit by the following equation:

<u>Equation 2</u>

$$T_{CO2e} \geq \sum_{i=1}^{365} \frac{(W_{CO2e}\ x\ 1020\ x\ V_{Di})}{2000}$$

Where:

T_{CO2e} =	130,263 CO_{2e} ton/yr limit in Special Condition III.A, Table 1
W_{CO2e} =	117 lb CO_{2e}/MMBtu
1020 =	Conversion factor (MMBtu/Mscf)
V_{Di} =	Daily average volumetric flow rate of natural gas to the boiler (Mscf)
2000 =	Conversion factor (lb/ton)

3. Work Practice and Operational Requirements

a. To demonstrate compliance with the BACT emission limits the Permittee shall calculate the lb CO2e/MMBtu at least once every day. The Permittee shall monitor and record hourly average CO_2 concentrations (% CO_2) and hourly average stack gas volumetric flow rate (scfh) from the boiler at least once a day. The Permittee shall monitor and record the hourly volumetric flow rate of natural gas to the boiler (Mscf) at least once per hour.

b. Compliance with the 365-day rolling average ton CO_{2e}/365-day BACT emission limit shall be determined at least once every day after 365 days of data have been recorded. The Permittee shall monitor and record the daily average volumetric flow rate of natural gas to the boiler (Mscf) at least once a day.

c. The Permittee shall compare the calculated CO_{2e} emissions from Special Condition III.B.1. Compliance with lb CO_{2e} /MMBtu BACT Emission Limit and Special Condition III.B.2. Compliance with ton CO_{2e} / 365 day BACT Emission Limit to the allowable BACT CO_{2e} limit required in Special Condition III.A Point Source Emission Limits. The calculated CO_{2e} emissions shall be less than the allowable BACT CO_{2e} limit. If the Permittee finds that the calculated CO_{2e} emissions rate is greater than the allowable BACT CO_{2e} limit, the Permittee shall review the operational performance of the emission unit and monitoring instrumentation. From this review, any necessary corrective measures shall be identified and recorded by the Permittee, including the reason for the CO_2 emissions difference. The Permittee shall complete corrective measures within 48 hours of identification of a difference and comply with Section IV., Recordkeeping Requirements.

d. The Permittee shall install, maintain and operate a non-resettable elapsed flow meter, to measure the flow rate of the fuel combusted in the natural gas fired boiler. Flow rate will be recorded at least once per day and recorded as Mscf.

e. The Permittee shall install, maintain and operate a continuous emission monitor (CEM) on the exit stack of the natural gas fired boiler to monitor hourly average CO_2 concentrations (% CO_2). Hourly average CO_2 concentrations will be recorded at least once per day and recorded as (% CO_2).

f. The Permittee shall install, maintain and operate a flow meter to measure the hourly average stack gas volumetric flow rate (scfh) exiting the natural gas fired boiler. This shall be recorded at least once per day and recorded as scf.

g. The Permittee shall install and maintain a minimum of 4 inches of insulation around the boiler at all times.

h. The Permittee shall install, maintain and operate NO_x control requirements as required by the Wyoming DEQ PSD permit for this boiler.

i. The Permittee shall install, maintain and operate during all times, a boiler blowdown tank and in-stack economizer.

j. The Permittee shall ensure that all ducting for boiler intake air draws air from at or above the process building roofline.

k. The Permittee shall ensure that the natural gas boiler is integrated into the existing Solvay steam production system.

l. The Permittee shall ensure that Maintenance and Operation requirements that include yearly steam line inspections, maximized condensate recovery and usage of an anti-scalant additive to the boiler feed water are established and implemented for this natural gas fired boiler.

m. The Permittee shall maintain and operate the emission unit to ensure the GHG emissions are continuously at or below the emissions limits specified in this permit.

IV. RECORDKEEPING REQUIREMENTS

A. Including any recordkeeping requirements specified elsewhere in this permit, the Permittee shall maintain a file of all records, data, measurements, reports, and documents related to the operation of this boiler, including, but not limited to, the following: all records or reports pertaining to significant maintenance performed on any system or device related to the operation of this boiler; all records relating to performance tests and monitoring of auxiliary combustion equipment; and other information required by this permit recorded in a permanent form suitable for inspection. The file must be retained for not less than 5 years following the date of such measurements, maintenance, reports, and/or records.

B. The Permittee shall maintain the following records for at least 5 years, including:

1. the occurrence and duration of any startup, shutdown, malfunction;

2. duration of any initial shakedown period for the emission unit;

3. calibration tests of flow meters required by Condition V.A. Performance Testing Requirements used to demonstrate compliance with this permit;

4. the time and duration of any periods that monitoring devices are not operating;

5. all data recorded in compliance with Special Conditions III.B.1. Compliance with lb CO_{2e} /MMBtu BACT Emission Limit through III.B.3. Work Practice and Operational Requirements; and

6. all CEMS testing, maintenance, and calibration checks conducted to satisfy quality assurance requirements under Condition V.B. Performance Testing Requirements.

C. The Permittee shall maintain records of any exceedance of limitations in this permit and submit a written report of all exceedances to EPA semi-annually except when: more frequent reporting is specifically required by an applicable subpart; or the authorized representative of the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30th day following the end of each semi-annual period and shall include the following:

1. time intervals, data and magnitude of the exceedance, the nature and cause (if known), corrective actions taken and preventative measures adopted;

2. applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time);

3. if no exceedances of a permit limit occurred during the reporting period or the monitoring equipment has not been inoperative, repaired or adjusted, a statement that no exceedance of that limit occurred, and/or that the monitoring equipment has not been inoperative, repaired or adjusted (as applicable), shall be submitted;

4. any failure to conduct any required source testing, monitoring, or other compliance activities; and

5. any violation of limitations on operation, including but not limited to restrictions on hours of operation of the emergency generator.

D. Exceedance shall be defined as any period in which the facility emissions or other parameter of operation exceed a maximum limit set forth in this permit.

E. Excess emissions indicated by GHG emission source certification testing or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.

F. All records required by this PSD Permit shall be retained for not less than 5 years following the date of such measurements, maintenance, and reports.

V. PERFORMANCE TESTING REQUIREMENTS

A. The Permittee shall calibrate, according to manufacturer's specifications, all flow meters used to comply with Special Condition III.B.3.d. Work Practice and Operational Requirements at least once per calendar year.

B. The Permittee shall calibrate daily the CEM used to comply with Special Condition III.B.3.e. Work Practice and Operational Requirements, according to manufacturer's specifications. In addition, the Permittee shall perform a relative accuracy test audit of the CEM used to comply with Special Condition III.B.3.e. Work Practice and Operational Requirements at least once per calendar year. This test audit shall be conducted under the procedures described in 40 CFR Part 60, Appendix F.

C. The Permittee shall maintain records of all performance tests as required under Special Condition IV. A. 6. Recordkeeping Requirements.

VI. AGENCY NOTIFICATIONS

A. The Permittee shall submit GHG permit applications, permit amendments, and other applicable permit information to:

Air Program (8P-AR)
US EPA Region 8
1595 Wynkoop St.
Denver, CO 80202

B. The Permittee shall submit a copy of all compliance and enforcement correspondence as required by this permit to:

Air Technical Enforcement Program (8ENF-AT)
US EPA Region 8
1595 Wynkoop St.
Denver, CO 80202

C. For any notifications required to be delivered to EPA within a certain time frame, fulfillment of the requirement can be accomplished by delivery of the required information to EPA in writing, postmarked by such date.

Authorized By: United States Environmental Protection Agency, Region 8

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Debra H. Thomas
Acting Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance (OPRA)

Date: ______________________________

Statement of Basis

Greenhouse Gas Prevention of Significant Deterioration Draft Pre-Construction Permit for the Solvay Soda Ash Joint Venture, Green River Soda Ash Plant

Permit Number: PSD-WY-000004-2012.001

DATE December 12, 2013

This document serves as the Statement of Basis (SOB) required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, and 40 CFR 52.37 (Federal Implementation Plan (FIP) to issue permits under the Prevention of Significant Deterioration (PSD) requirements to sources in certain states that emit greenhouse gases), that would apply if the permit is issued. This document is intended for use by all parties interested in the permit.

I. Executive Summary

In August, 2012, Solvay Soda Ash Joint Venture (Solvay) submitted to the Environmental Protection Agency Region 8 (EPA) a PSD permit application for a Greenhouse Gas (GHG) emissions permit associated with the modification of its Green River soda ash facility located near Green River, Wyoming. Additional information was submitted on August 12, 2013. In connection with the same proposed project, Solvay submitted a PSD permit application for non-GHG pollutants to the Wyoming Department of Environmental Quality (WDEQ) Air Quality Division (AQD). The proposed modifications are intended to de-bottleneck the facility's soda ash and related products production circuits. This involves adding a steam boiler, which will be the only new source of air emissions. The de-bottlenecking will also include adding a heat exchanger, which will utilize available steam heat for the purpose of speeding up the crystallization processes. The combination of adding the steam boiler and heat exchanger will serve to increase both short-term and long-term production while remaining within the previously permitted design rates. After reviewing the application, EPA has prepared the following SOB and a draft New Source Review (NSR)/PSD pre-construction air permit to authorize construction of a GHG air emission sources at the Solvay facility.

This SOB documents the information and analysis EPA used to support decisions made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

Solvay submitted additional information on August 12, 2013 to EPA. This submittal contained information to assist EPA in making determinations applicable to the Endangered Species Act (ESA) Section 7, National Historic Preservation Act (NHPA) Section 106, and issues relating to Environmental Justice (EJ).

EPA concludes, subject to consideration of public comment, that Solvay's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable PSD air permit regulations for GHG. EPA's initial conclusions rely upon information provided in the permit application, supplemental information submitted to EPA by Solvay in response to EPA's request, and

EPA's own technical analysis. EPA is making all of this information available as part of the public record for the permit application.

II. Applicant

Solvay Soda Ash Joint Venture
Green River Soda Ash Plant
P. O. Box 1167
Green River, WY 82935

Physical Location:
Green River Soda Ash Plant
NE Quarter, Section 31, Township 18 North, Range 109 West
Sweetwater County, Wyoming

Owner/Operator:
Solvay Soda Ash Joint Venture
Green River Soda Ash Plant

Responsible Official: Mr. Ronald O. Hughes, (307) 875-6500
Permit Contact: Mr. Tim Brown, (307) 875-6500

III. Permitting Authority

On December 30, 2010, EPA published a FIP making EPA the GHG PSD permitting authority for states that do not have the authority to implement GHG PSD permitting. 75 FR 82246 (promulgating 40 CFR 52.37). Wyoming still retains approval of its State Implementation Plan (SIP) and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

The GHG PSD permitting authority for the state of Wyoming is:

EPA, Region 8
1595 Wynkoop St.
Denver, CO 80202

Permit Author:
Donald Law
Air Permitting Monitoring and Modeling Unit (8P-AR)
(303) 312-7015

The non-GHG PSD permitting authority for the state of Wyoming is:

Air Quality Division
Wyoming Dept. of Environmental Quality
122 West 25th Street
Cheyenne, WY 82002

IV. Public Notice, Comment, Hearings and Appeals

Public notice for the draft PSD GHG permit will be published on December 12, 2013, in the Rock Springs Rocket-Miner. The public comment period will begin on December 12, 2013 and close on January 13, 2013, at 8:30 p.m. During the public comment period, the public will be given the opportunity to review a copy of the permit application, the draft permit prepared by EPA, the SOB, and permit-related correspondence. The draft permit, SOB, and Administrative Record for the draft permit will be available for review at EPA Region 8's office Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays). The permit application, draft permit and SOB will also be available for review on EPA's website at http://www.epa.gov/region8/pubnotice.html, under the heading "Region 8 Air Permitting comment opportunities" within the "PSD Permits" heading. A hardcopy of these documents will also be available for review at the Sweetwater County Clerk's Office in Green River, Wyoming, Monday through Friday from 8:00 a.m. to 5:00 p.m. until the close of the public comment period.

In accordance with 40 CFR 52.21(q), *Public participation*, any interested person is afforded the opportunity to submit written comments on the draft permit during the public comment period and to request a hearing. If requested during the public comment period, a public hearing will be held for this action. The purpose of the hearing is to gather comments concerning the issuance of the EPA GHG PSD permit. The scope of the hearing will be limited to such issues in order for the EPA to determine whether or not the applicable PSD Regulations have been appropriately applied to the construction and operation of the proposed boiler. Oral statements will be accepted at the time of the hearing, but for accuracy of the record, written statements are encouraged and will be accepted at the time of the hearing or prior thereto. Since the EPA is not the permitting authority for the remainder of the NSR pollutants, a public hearing regarding the WDEQ draft PSD permit would not be covered by a public hearing on the EPA GHG permit.

In accordance with 40 CFR 124.13, *Obligation to raise issues and provide information during the public comment period*, anyone, including the permit applicant, who believes any condition of the draft permit is inappropriate, or that EPA's tentative decision to prepare a draft permit for the project is inappropriate, must raise all reasonably ascertainable issues and submit all arguments supporting the commenter's decision, by the close of the public comment period.

Any supporting materials submitted must be included in full and may not be incorporated by reference, unless the material has been already submitted as part of the administrative record in the same proceeding or consists of state or federal statutes and regulations, EPA documents of general applicability, or other generally available reference material. An extension of the 30-day public comment period may be granted if the request for an extension adequately explains why more time is needed to prepare comments.

In accordance with 40 CFR 124.15, *Issuance and Effective Date of Permit*, the permit shall become effective immediately upon issuance as a final permit, if no comments request a change in the draft permit. If changes are requested, the permit shall become effective thirty days after issuance of a final permit decision. Notice of the final permit decision shall be provided to the permit applicant and to each person who submitted written comments or requested notice of the final permit decision.

In accordance with 40 CFR 124.19, *Appeal of RCRA, UIC, and PSD Permits*, any person who filed comments on the draft permit or participated in the public hearing may petition the Environmental Appeals Board, within 30 days after the final permit decision, to review any condition of the permit decision. Any person who failed to file comments or failed to participate in the public hearing on the draft permit may petition for administrative review only on changes from the draft to the final permit decision.

V. Facility Location

The Solvay facility is located in Sweetwater County, Wyoming. A portion of Sweetwater county is currently designated as non-attainment for the ozone National Ambient Air Quality Standard (NAAQS). However, the Solvay facility is not located within this non-attainment area The portion of Sweetwater county where the Solvay facility is located is is currently considered to be in attainment for all of NAAQS. The nearest federal Class 1 area is Bridger Wilderness Area. The geographic coordinates for this facility are as follows:

NE Quarter, Section 31, Township 18N, Range 109W
Latitude 41.501, Longitude -109.758

VI. Applicability of Prevention of Significant Deterioration (PSD) Regulations

Under EPA's Clean Air Act permitting rules, the term "greenhouse gas" means an air pollutant consisting of the aggregate of six gases with atmospheric warming potential: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). GHG emissions are determined by multiplying the mass emissions of each of these gases, in tons per year (tpy) by its respective Global Warming Potential (GWP) and summing the result, which is referred to as the "CO_2-equivalent" (CO_{2e}). The GWPs (40 CFR 98, Table A-1) are 1.0 for CO_2, 21 for CH_4, and 310 for N_2O. No emissions of HFCs, SF_6 or PFCs are expected from this project.

EPA concludes that Solvay's application is subject to PSD review for GHG because the project would lead to a GHG emissions increase as described at 40 CFR § 52.21(b)(49)(iv). The proposed project emissions would result in increased GHG emissions above both of the PSD applicability thresholds, which are 0 tpy on a mass basis and 75,000 tpy on a CO_2e basis. Solvay has presented CO_2e potential mass emissions of 130,263 tpy for this project. The project's potential GHG emissions on a mass basis are 130,049 tpy. EPA is the permitting authority responsible for implementing a GHG PSD FIP for Wyoming under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.37.

As the permitting authority for regulated NSR pollutants other than GHGs, WDEQ has determined the proposed project is subject to PSD review for non-GHG pollutants. Specifically, the PSD application submitted to WDEQ explains the proposed facility will be a major modification to an existing major stationary source. Accordingly, WDEQ will issue the non-GHG portion of the PSD permit and EPA Region 8 will issue the GHG portion.[1]

As part of its analysis, EPA considers the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011) (Guidance), available on EPA website at: www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf. Consistent with the recommendations in that Guidance, we have not required the applicant to model or conduct ambient monitoring for GHG, since there are no ambient air quality standards for GHGs, and we have not required any assessment of impacts of GHG in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the Best Available Control Technology (BACT) analysis is the best technique that can be employed, at present, to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHG. We note again, however, that the project has triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD permit sought from WDEQ.

For a description of the five-step process involved in making a PSD BACT determination for GHGs, please refer to the aforementioned Guidance and sources there cited. EPA has followed those steps in making the GHG BACT initial determination for this project.

VII. Project Description

The Solvay natural gas boiler project proposes to construct a new natural gas fired boiler that will add steam-generating capacity to the Solvay facility. The addition of this natural gas fired boiler with the two existing coal-fueled boilers will allow Solvay the operational flexibility to (1) shut any one of the three boilers down for maintenance without curtailing production, and (2) take advantage of the lower-cost fuel (coal vs. natural gas).

With this project, Solvay expects to increase annual soda ash production by approximately 14 percent. This permit modification assumes no operational limit on combined steam production, and the additional boiler will be permitted to operate at capacity. In this way, the gas-fueled boiler could run at its maximum while the coal boilers would supplement as needed, or the coal-fueled boilers could operate at their capacity while the gas boiler would supplement the steam demand.

This additional boiler is a water tube package boiler natural gas fired (a Foster Wheeler Model AG 5195, 254 MMBtu/hr boiler) that was installed previously in Garfield County, Colorado at the American Soda facility. It was used from 2000 through May 2004 and then permanently shut down. It is a boiler capable of producing 200,000 lbs. of steam per hour, to be added in parallel to the two 300,000 lbs. per hour coal boilers. In 2003, Solvay purchased the American Soda facility in Garfield County, Colorado, including the Foster Wheeler Model AG 5195 natural gas fired boiler. The boiler will be fueled through the Western Gas Pipeline by a spur currently feeding the Solvay plant.

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting authorities (April 19, 2011), http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

Short-term production capacity will not change, although the addition of the heat exchanger will allow short-term actual production to increase and come nearer to capacity. On an annual basis, this additional steam production will enable the plant to continue production during boiler maintenance so there can also be an increase in long-term actual production. Solvay anticipates actual annual soda ash production to increase by 360,000 tons from the current actual level of 2.55 to 2.91 million tons. Depending on the mix of boiler use between coal and gas, the group of boilers' criteria pollutants and CO_2e emissions could increase. The gas boiler emissions are lower on a per-unit-of-steam-basis than the emissions from the coal boilers. If the gas boiler were to operate at capacity with the coal boilers cut back, boiler emissions of at least NO_x, and CO_2e would decrease. Emissions from the other existing fueled sources, which are the calciners and some dryers, could increase with increased production since they operate in series with the steam-heated crystallizers.

Table 1 – GHG Emissions from Solvay Project

GHG	Mass Emissions, tpy	Global Warming Potential	Project GHG emissions (as CO_2e, tpy)
Carbon Dioxide (CO_2)	130,041	1	130,041
Methane (CH_4)	6.97	21	146
Nitrous Oxide (N_2O)	0.25	310	76
Project Emissions, tpy	130,049		130,263

VIII. BACT Analysis

The BACT analysis provided by the applicant included the assumptions described below, which have been considered and modified by EPA in its own BACT analysis.

1. Table 1 presents estimated Solvay GHG emissions in terms of CO_2e emissions, and only includes emissions of CO_2, CH_4, and N_2O. The project is not expected to emit HFCs or PFCs because these man-made gases are primarily used as cooling, cleaning, or propellant agents.

2. From the GHG emissions inventory presented in Table 1 above, CH_4 and N_2O total only approximately 222 tpy of CO_2e emissions, which is about 0.17% of total CO_2e emissions. As this project is primarily considering options to bolster energy efficiency at the facility and reductions in CO_2 relate to fuel usage that also provides a reduction of CH_4 and N_2O, this permit will examine the CO_2 emissions as essentially a surrogate for CO_2e.

The project will include one new GHG-emitting emission unit that is subject to BACT: the Foster Wheeler 254 MMBtu/hr natural gas fired boiler.

Foster Wheeler 254 MMBtu/hr Boiler CO_2 Emissions

Step 1 Identify Potential Control Technologies

In discussions with EPA about the use of the existing, owned, and available boiler, Solvay stated that the proposed unit is a 10+ year old Foster-Wheeler unit. Information supplied by Foster Wheeler indicates that this proposed unit is designed to operate at 83-85% efficiency at high heating value and that a new unit of the same size and current technology would have a similar design efficiency (83-85%). Given this similarity in beginning efficiency, a new boiler will not be considered as a possible BACT option for this project.

The gas-fueled boiler is being added to the Solvay plant to supplement the steam provided by existing coal-fueled boilers, but it could also be used as a base load while varying the steam production of the coal-fueled boilers to meet capacity. In this way, the CO_2e would be reduced because the GWP per unit of heat from coal is higher than the CO_2e for heat from natural gas (94 kg CO_2/MMBtu v 53 kg CO_2/MMBtu). Solvay asserts that the flexibility to use the boilers as best meets the needs of the plant is its choice and that the BACT analysis does not extend to this level of controlling the mix of boiler usage. EPA agrees with Solvay's need for operational flexibility.

Technology related to maximizing steam boiler energy efficiency is provided in the ICI Boiler Manual, which addresses feasible efficiency-increase technologies as a surrogate for CO_2 control technologies for steam boilers. At 254 MMBtu per hour, the Solvay boiler fits well within the class of ICI boilers addressed. Table 2 lists the entries as feasible options for maximizing energy efficiency. Solvay grouped the methods of increasing thermal efficiency from a boiler as follows: 1) Efficient design of boiler and associated steam delivery equipment, 2) Efficient operation of equipment, 3) Good maintenance, and 4) Other measures.

TABLE 2: BACT Control Options

Group	BACT Option	Technical Feasibility	Description
Efficient Boiler Design and Steam Delivery			
	High Efficiency Burner	Yes	Ultra-Low NOx Burner (UNLB) is part of the design.
	Refractory Material Selection	Yes	Best available already included in boiler design.
	Economizer Usage	Yes	Part of Boiler Design. Exhaust temp of 320 F or less.
	Blowdown Heat Recovery	Yes	Blowdown sent to flash tank as part of boiler design.
	Condensate Recovery For Boiler Reuse	Yes	Maximum amount the steam circuit will accept based on water quality requirements. All condensate is recovered for use in the plant.
	Combustion Air-Preheater	Yes	Combustion air is drawn from the process building roof line which is approximately 20 F warmer than building ground level air.
	Increased Boiler Insulation	Yes	Boiler designed for 3 inches. Solvay agrees to install additional insulation to achieve at least 4 inches.
	Increased Refractory Lining	No	Additional Refractory Lining would require boiler redesign.

Efficient Operation of the Boiler and Steam Distribution Equipment			
	Energy Management Systems	Yes	Boiler will be connected into the current steam management system and will be controlled by Solvay's current energy management system.
	Good O&M Practices	Yes	
	Boiler Instrumentation and Control	Yes	Additional control is included with ULNB to meet NOx & CO emission limits.
Good Maintenance			
	Steam Line Maintenance	Yes	Scaling to be controlled with anti-sealant additive. Pipes to be visually checked at least quarterly and insulation replaced as needed.
	Minimization of Air Infilitration	No	
	Minimization of Gas-side Heat Transfer Deposits	No	
	Minimize Steam Trap Leaks	Yes	Inspected and repaired at least annually.
Other Measures			
	Turbine Shaft Power Extracted from High Pressure Steam	Yes	Included in existing steam circuit. There are 9 turbines powering 4 ducted fans and 5 pumps. Turbines eliminate use of electrical power.
	Carbon Capture and Storage	Yes	

Step 2 Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates from consideration any technically infeasible options. EPA generally considers a technology to be technically feasible if it: (1) has been demonstrated and operated successfully on the same type of source under review, or (2) is "available" and "applicable" to the source type under review. See Guidance at 33. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Efficient Boiler Design and Steam Delivery

Within the Efficient Boiler Design and Steam Delivery grouping, Solvay indicated that increasing the thickness of the refractory lining was technically infeasible. As this boiler is already owned by Solvay but located at a different facility, it would be impossible to specify refractory thickness as a part of this boiler design. As such, EPA agrees with Solvay that increasing the refractory thickness is technically infeasible for this project.

Good Maintenance

Minimization of Air Infiltration

At EPA's request, Solvay provided additional information on August 12, 2013 concerning their claim that minimizing air infiltration is not technical feasible for the project's boiler. Solvay's natural gas boiler will operate at positive pressure (18.51 inches of water.) Therefore, the boiler will operate at a pressure higher than the environment surrounding the boiler. When the boiler is operating, the higher pressure air from the boiler will exert outward forces from the boiler which would eliminate air infiltration into the boiler. Due to this boiler design, EPA agrees that minimization of air infiltration is not technically feasible as a BACT option.

Minimization of Gas-side Heat Transfer Deposits

Solvay provided additional information on August 12, 2013 concerning their claim that minimizing gas-side heat transfer deposits is not technically feasible for the project's boiler. The build-up of deposits on the gas-side of the heat transfer tubes within a boiler occurs due to the presence of long chain hydrocarbons within the gas stream. Due to the composition of natural gas, the build-up of these deposits on the gas-side of the heat transfer tubes is not to be expected. Therefore, EPA agrees that minimization of gas-side heat transfer deposits is not applicable here, and is not considering it.

Other Measures

Carbon Capture and Storage

CCS technology is composed of 3 main components: (1) CO_2 capture, including compression; (2) CO_2 transport, and; (3) permanent CO_2 storage or sequestration.

CCS systems involve the use of adsorption or absorption processes to separate and capture CO_2 from the flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The concentrated CO_2 is then compressed to "supercritical" temperature and pressure, a state in which CO_2 exists neither as a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR) or through ocean sequestration.

The capture of CO_2 from the gas streams can be accomplished using either physical or chemical solvents or solid sorbents. Applicability of different processes to particular applications will depend on temperature, pressure, CO_2 concentration, and contaminants in the gas or exhaust stream.

After separation, the CO_2 must be compressed to supercritical temperature and pressure for suitable pipeline transport. While compressor systems for such applications are proven and commercially available, the technologies require specialized equipment and the operating energy requirements are very high.

The supercritical CO_2 would then be transported to an appropriate location for injection into a suitable storage reservoir. The transport options may include pipeline or truck transport, or in the case of ocean storage, transport by oceangoing vessels.

CO_2 storage methods include geologic sequestration, oceanic storage, and mineral carbonation. Oceanic storage, as discussed below, has not been demonstrated in practice and is not currently practical to CO_2 captured in Wyoming. Geologic sequestration is the process of injecting captured CO_2 into deep subsurface rock formations for long-term storage, which includes the use of a deep saline aquifer or depleted coal seams, as well as the use of compressed CO_2 to EOR in crude oil production operations.

Under geologic sequestration, a suitable geological formation is identified close to the project location and the captured CO_2 from the process is compressed and transported to the sequestration location. CO_2 is injected into that formation at a high pressure and to depths generally greater than 2,625 feet (800 meters).

Below this depth, the pressurized CO_2 remains "supercritical" and behaves like a liquid. Supercritical CO_2 is denser and takes up less space than gaseous CO_2. Once injected, the CO_2 occupies pore spaces in the surrounding rock, like water in a sponge. Saline water, which already resides in the pore space would be displaced by the denser CO_2. Over time, the CO_2 can dissolve in residual water and chemical reactions between the dissolved CO_2 and rock can create solid carbonate minerals, more permanently trapping the CO_2.

There are several geologic formations identified across Wyoming that might provide a suitable site for geologic sequestration. Based on the NETL 2010 Big Sky Carbon Sequestration Partnership (BSCSP) atlas, potentially suitable sequestration basins are located immediately in the vicinity of Green River and Rock Springs, Wyoming, providing potentially feasible deep saline formations (NETL, 2010). However no exploratory work or injection pilot testing into the geological formations near these areas has been conducted to date, so the actual suitability of these formations is unknown.

According to NETL/BSCSP, there are no active CCS projects operating within Wyoming, making the logistical and capital costs unclear as to the efficient use of these basins. Further, the geotechnical analyses needed to confirm their suitability have not been conducted. As such, the analysis of transport options must consider long distances potentially required to reach existing storage locations.

Ocean storage is accomplished by injecting CO_2 into the ocean water typically below 1,000 meters via pipe or ship. At these depths, CO_2 is expected to dissolve or form into a horizontal lens which would delay the dissolution of CO_2 into the surrounding environment. The depth of the overlying water and the lensing of the CO_2 will form a natural impediment to the vertical movement of the injected CO_2.
In mineral carbonation, captured CO_2 is reacted with metal-oxide bearing materials, thus forming the corresponding carbonates and a solid byproduct.

Geological sequestration of CO_2 through EOR is relatively well understood and is being implemented at full scale at many locations across the U.S. According to the CCS Interagency Task force "approximately 50 million tons of CO_2 per year are injected, produced with oil, captured, and re-injected" (ICCS, 2010). EOR consists of injecting CO_2 into an existing oil field where it can mix with crude oil, causing the conditions for additional pressure and ability to extract oil from otherwise diminished production sites. CO_2 is then extracted from the crude oil produced and re-injected into the formation to maintain constant recovery rates. Limiting factors to EOR include transportation of captured CO_2 to available oil field operations and the availability of infrastructure to do so.

Sequestration of available CO_2 through mineral carbonation can be accomplished by combining CO_2 with available calcium or magnesium carbonates, such as serpentine or olivine to form carbonate minerals such as calcite, dolomite, and magnesite. The process is accomplished in an industrial (ex situ) setting or in situ by injecting into mineral rich deposits. Mineral carbonation has been studied for some time and the research into the practical implementation as a sequestration technology is on-going. Challenges include slow kinetic reactions, proximity of available mineral deposits to CCS operations, and the large volume of energy required to drive the carbonation process.

Solvay's initial GHG PSD application considered CCS to be technically infeasible for this project. EPA recognizes some of the technical and logistical challenges of a CCS system for the Solvay boiler project; however, EPA considers CCS as a technically feasible option.

Step 3 Rank Remaining Control Technologies by Control Effectiveness.

Due to the nature of the BACT options considered for this project, a control effectiveness ranking was not done for this project. Any BACT option determined to be cost effective and technically feasible will be selected for this project.

Step 4 Evaluate Economic, Energy and Environmental Impacts.
Carbon Capture and Storage

Solvay supplied additional information to EPA discussing the economic viability of CCS applicability to their project. This information was submitted in August 2013. In its supplemental submission, Solvay utilized cost estimates from another similar project at the Solvay facility, referred to as the MEA CO_2 Extraction Project (MEA project). For the MEA project, Solvay considered the cost of capturing/removing CO_2 (post-combustion) from one of its two coal-fired boilers at the facility. The MEA project cost included CO_2 capture, but did not include compression, transportation, and storage of CO_2, therefore providing a low-end (conservative) estimate of CCS costs for the natural gas boiler project.

Union Engineering estimated costs for removal of ~118,000 tpy CO_2 from the Solvay coal boiler flue gases with a 10.6 percent concentration of CO_2 in the exhaust stream. For comparison, the CO_2 emissions available from capture from Solvay's natural gas boiler are ~130,000 tpy CO_2 at capacity with CO_2 flue gas concentrations around six percent. The MEA project was designed to remove approximately 90 percent of the mass of CO_2 of the current boiler project, so the projects are similar in size.

Attachment B, Page 1of the August 2013 Supplement provides Solvay's total cost estimate of $25,675,625 for the MEA CO_2 capture project. These total project capital costs include the costs of materials, equipment, construction, services, operating expenses, and project contingencies. Attachment B, Pages 2 through 26, provide a budget quote from Union Engineering for the CO_2 capture equipment package which is included in the total MEA project costs. These costs do not include any costs associated with compression, transportation, or CO_2 storage.

As provided in Attachment C of the August 2013 Supplement, Solvay estimates the total cost of the natural gas boiler project at $12,506,350. This is the same cost used by management in the past to determine the production viability of the project for production economics purposes.

Therefore, the estimated post-combustion capture capital costs for the MEA CO_2 capture project ($25,675,625) are roughly twice the total capital costs of the natural gas boiler project ($12,506,350). EPA expects that overall CCS costs associated with reduced CO_2 capture (e.g., less than 90%) for the natural gas boiler project would not be appreciably different for this size and type of boiler. For the Sinclair Refinery GHG PSD project, EPA determined that a post-combustion capture cost to project cost ratio of 0.71 was financially prohibitive. Solvay's capture cost to project cost ratio of 2.05 is nearly three times higher than the Sinclair Refinery project, and these costs do not consider the additional costs of compressing, transporting, and storing the CO_2. Furthermore, there are additional energy requirements to operate a CO_2 capture and compression system that would increase the overall cost of the CCS system, and potentially increase emissions of other pollutants. As such, CCS is rejected under Step 4 of the BACT analysis for its natural gas boiler project.

Non-CCS Control Options

All non-CCS control options under consideration in Step 1 of the BACT analysis are either technically feasible or they have acceptable economic, energy, or environmental impacts.

Step 5 Select BACT and Document Results

BACT for the Solvay natural gas boiler project will include all of the following:

- A minimum of 4 inches of insulation on all insulated boiler components;
- NOx controls as required by the Wyoming PSD permit for this project;
- Installation and usage of a boiler blowdown tank and in-stack economizer;
- Ducting of boiler intake air from the process building roofline;
- Integration of this boiler into the existing Solvay steam production system; and
- Maintenance and Operation requirements that include yearly steam line inspections, maximized condensate recovery and usage of an anti-scalant additive to the boiler feed water.

The initial Solvay GHG permit application stated that Ultra-Low NOx burners would be used on the boiler as NOx control. However, at the time this document was written, the criteria pollutant PSD permit for this project had not yet been finalized by WDEQ. Therefore, the BACT for GHG will include the NOx controls that will be required by WDEQ and stated in the WDEQ permit.

In addition, Solvay proposes a long and short-term emission limit for CO_2e. Proposed limits are 130,263 tons per year, and 125.3lb per MMBtu, (HHV) respectively.

For the long-term limit, the maximum annual CO_2e emissions are proposed to be the emissions using the boiler Manufacturer Capacity Rating (MCR) which is 254 MMBtu/hr, boiler operation for 365 days/yr., and nominal natural gas quality emissions provided by EPA in 40 CFR Part 98, Subpart C, Table C-1. That nominal value is a CO_2e emission factor of 117 lb / MMBtu. This estimation calculation is shown in Appendix D of the August 2012 PSD application and results in an annual emission limit of 130,263 tons per year.

The short-term (hourly) CO_2e limit will be in the form of a mass of CO_2e per unit of energy input to the boiler. Pipeline gas is primarily composed of methane, but can have varying percentages of the hydrocarbon constituents (methane, ethane, propane, butane, pentane and hexane, etc) and also varying percentages of CO_2 among other passive constituents. The boiler manufacturer provided Solvay an estimate of the maximum heat content pipeline fuel that the boiler could experience in NW Colorado and this fuel analysis is presented on page 2 of Appendix A of the August 2012 PSD application. EPA believes that the qualities of the natural gas available in Sweetwater County, Wyoming are significantly similar enough to the natural gas available in NW Colorado for this estimate to remain accurate for this analysis. The CO_2 emissions associated with this gas composition are estimated on the final page of Appendix D August 2012 PSD application, using the constituent-specific CO_2 emissions per unit mass of the constituent and assembling these according to the quantity of the constituent in that fuel analysis. The CH_4 and N_2O components in the exhaust are expected to be approximately the same as for nominal natural gas and these fixed factors are added to the measured CO_2 to determine the total CO_2e short-term emission limit. These factors are 0.05 and 0.07lb/MMBtu respectively.

The CO_2 measurement will be by continuous emission monitor for exhaust concentration and associated with a continuously measured flow rate using Equation C-6 of 40 CFR Part 98.33 (a)(4)(ii). Using this method, the Solvay short-term limit is 125.3 lb CO_2e per MMBtu heat input. This is 7 percent higher than the nominal pipeline natural gas value of 116.9lb CO_2e per MMBtu.

For purposes of demonstrating compliance on a short-term basis, a boiler heat input is needed. This will be achieved by measurement of the volume of fuel consumed by the boiler and coupling it with a Solvay monitored heat content.

Thus, there are three independent measurements being made using different plant control systems, CO_2 concentration, and exhaust flow rate from emissions monitoring, and boiler heat input from process controls. Solvay states that the shortest time interval over which this will be a meaningful calculation would be 24 hours, using hourly averaged or totaled measurements. Hourly calculations would likely contain inconsistencies because all the measurements would not have been collected at the same time, and, Solvay expects some hysteresis in the furnace response to fuel feed. In addition, the CO_2 and flow rate monitors could create additional inconsistency, so that the three combined may not track hour by hour. Solvay requests that the short-term CO_2 measurement be tracked on a 24-hour totalized basis. The estimate of CO_2e emissions per unit of heat input will be calculated and compared with the compliance limit every calendar day.

EPA agrees with these limits. However, the yearly limit will be calculated on a 365 day rolling average rather than a yearly basis and the short term limit will be calculated on a 24 hour average basis.

IX. Environmental Justice (EJ), Endangered Species Act (ESA), and National Historic Preservation Act (NHPA)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on EJ. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that EJ issues must be considered in connection with the issuance of federal PSD permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action authorizes emissions of GHG, controlled by what we have determined is the BACT for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no NAAQS for GHG. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGs at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an EJ analysis is not necessary for the permitting record.

The EPA has reviewed the proposed action for potential impacts on historic properties in the area of potential effect (APE). Based on our review of information from the permit applicant, National Park Service National Register of Historic Places and the Wyoming State Historic Preservation Office, we have determined that the proposed action should not affect any properties listed on the National Register of Historic Places. As presently designed, the proposed project will have no effect on known cultural resources. The results of the field inspection indicated that no new or previously identified cultural resources are located within the project area. The EPA is making the finding of "*No historic properties affected*" for the APE.

The proposed modification will be constructed within the existing boundaries of the Solvay facility in previously disturbed areas. The EPA has concluded that the proposed GHG PSD permit action will have "*no effect*" on listed species or critical habitat. If an action agency determines that the federal action will have no effect on listed species or critical habitat, the agency will make a "*no effect*" determination. In that case, the action agency does not initiate consultation with the Fish and Wildlife Service and its obligations under Section 7 are complete.

X. Conclusion and Action

Based on the information supplied by Solvay, our review of the analyses in the GHG PSD Permit Application and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed modification would employ BACT for GHG under the terms contained in the permit. Therefore, EPA is proposing to issue Solvay a draft PSD permit for GHG for the described project, subject to the PSD permit conditions specified therein.

ARTS. PARKS. HISTORY.
Wyoming State Parks & Cultural Resources

State Historic Preservation Office
2301 Central Ave., Barrett Bldg. 3rd Floor
Cheyenne, WY 82002
307-777-7697
FAX: 307-777-6421
http://wyoshpo.state.wy.us

RECEIVED
OCT 21 2013
8P-AR

Oct 17, 2013

Victoria Parker-Christensen
Environmental Protection Agency
Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

re: Proposed Modifications to the Solvay Soda Ash Joint Venture, Green River Soda Ash Plant (SHPO File # 1013BAB006)

Dear Ms Parker-Christensen:

Thank you for consulting with the Wyoming State Historic Preservation Office (SHPO) regarding the above referenced undertaking. We have reviewed the associated report and find the documentation meets the Secretary of the Interior's Standards for Archaeology and Historic Preservation (48 FR 44716-42). We concur with your finding that no historic properties, as defined in 36 CFR § 800.16(l)(1), will be affected by the undertaking as planned.

We recommend that the undertaking proceed in accordance with state and federal laws subject to the following stipulation:

If any cultural materials are discovered during construction, work in the area shall halt immediately, the federal agency must be contacted, and the materials evaluated by an archaeologist or historian meeting the Secretary of the Interior's Professional Qualification Standards (48 FR 22716, Sept. 1983).

This letter should be retained in your files as documentation of a SHPO concurrence on your finding of no historic properties affected. Please refer to SHPO project #1013BAB006 on any future correspondence regarding this undertaking. If you have any questions, please contact me at 307-777-8594.

Sincerely,

Brian Beadles
Historic Preservation Specialist

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

SEP 17 2013

Ref: P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mary Hopkins
State Historic Preservation Officer
Wyoming State Historic Preservation Office
2301 Central Avenue, Barrett Building, Third Floor
Cheyenne, Wyoming 82002

RE: Section 106 of the National Historic Preservation Act for Proposed Modification to the Solvay Soda Ash Joint Venture, Green River Soda Ash Plant in Sweetwater County, Wyoming

Dear Ms. Hopkins:

The Environmental Protection Agency Region 8 (EPA) has received an application for and is preparing a federal Clean Air Act, draft Prevention of Significant Deterioration (PSD) permit for greenhouse gas emissions associated with a proposed modification to the Solvay Soda Ash Joint Venture, Green River Soda Ash Plant located west of Green River in Sweetwater County, Wyoming. To comply with our obligations under Section 106 of the National Historic Preservation Act and its implementing regulations at 36 C.F.R. Part 800, we are consulting with you concerning our finding as to the potential effects and we are seeking any information you may have as to whether there are any historic properties within the area of potential effects (APE) for this project.

The Green River plant is an existing soda ash production plant. The proposed modifications intend to debottleneck soda ash and related products production circuits. This primarily involves adding a steam boiler, which will be the only new source of air emissions. The de-bottlenecking will include adding a heat exchanger, which will utilize available steam heat for the purpose of speeding up the crystallization processes. The combination will serve to increase both short-term and long-term production while remaining within the previously permitted design rates. The modification involves construction within the existing footprint at the Green River plant. Construction will involve a minimal amount of site preparation since the boiler will be installed within the existing facility. There will be not additional land clearing or road building. Preparation for the boiler will consist of excavation for the foundation, drilling of caissons and foundation pouring.

The plant is located in Sweetwater County in the NE Quarter, Section 31, Township 18N, Range 109W at latitude 41.501, longitude -109.758. The APE for the proposed modification is located within the area currently occupied by the Green River plant. A location map indicating the APE is enclosed with this letter.

The EPA reviewed the proposed action for potential impacts on registered historic properties. The National Park Service maintains an internet resource, the National Register of Historic Places database at http://www.nps.gov/history/nr/research/index.htm that was used to determine whether any registered historic places are within the APE. The results of the database search indicated that there are registered cultural places within Sweetwater County. Based on our review of this information, we have determined that the proposed action would not affect any properties listed on the National Register of Historic Places because these properties are located between 12 to 47 miles from the plant. A list of the registered properties is enclosed with this letter.

Therefore, based on our review of the National Register of Historic Places and given that the proposed modification will be constructed within the existing footprint of the plant, the EPA has made the finding "*No historic properties affected*" for the proposed draft PSD permit action. If you have any concerns regarding our determination, please notify me in writing within the 30 day time period described at 36 C.F.R. § 800.3(c)(4). If we haven't heard back from you within 30 days, we will assume you concur with our finding. In addition, please send any comments or information concerning historic properties within the project area to me within 30 days, so as to ensure that we will have ample time to review them. You can reach me by phone at (303) 312-6441 or email at parker-christensen.victoria@epa.gov. Thank you for your assistance.

Sincerely,

Victoria Parker-Christensen
Environmental Engineer
Air Program

Enclosures: Green River Soda Ash Plant and area of potential effects
List of Registered Historic Properties

Printed on Recycled Paper

Clean Air Act Federal Prevention of Significant Deterioration (PSD) of Air Quality Permitting for Solvay Soda Ash Joint Venture

Green River Soda Ash Plant
City Boundary
County Boundary

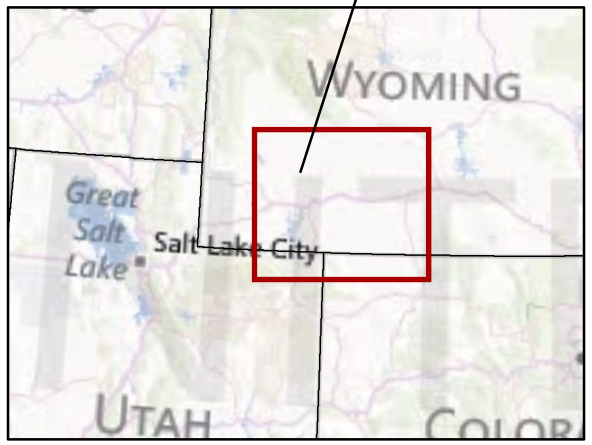
Date: September 16, 2013

Map Projection: UTM, Meters, Zone 13N, NAD83.

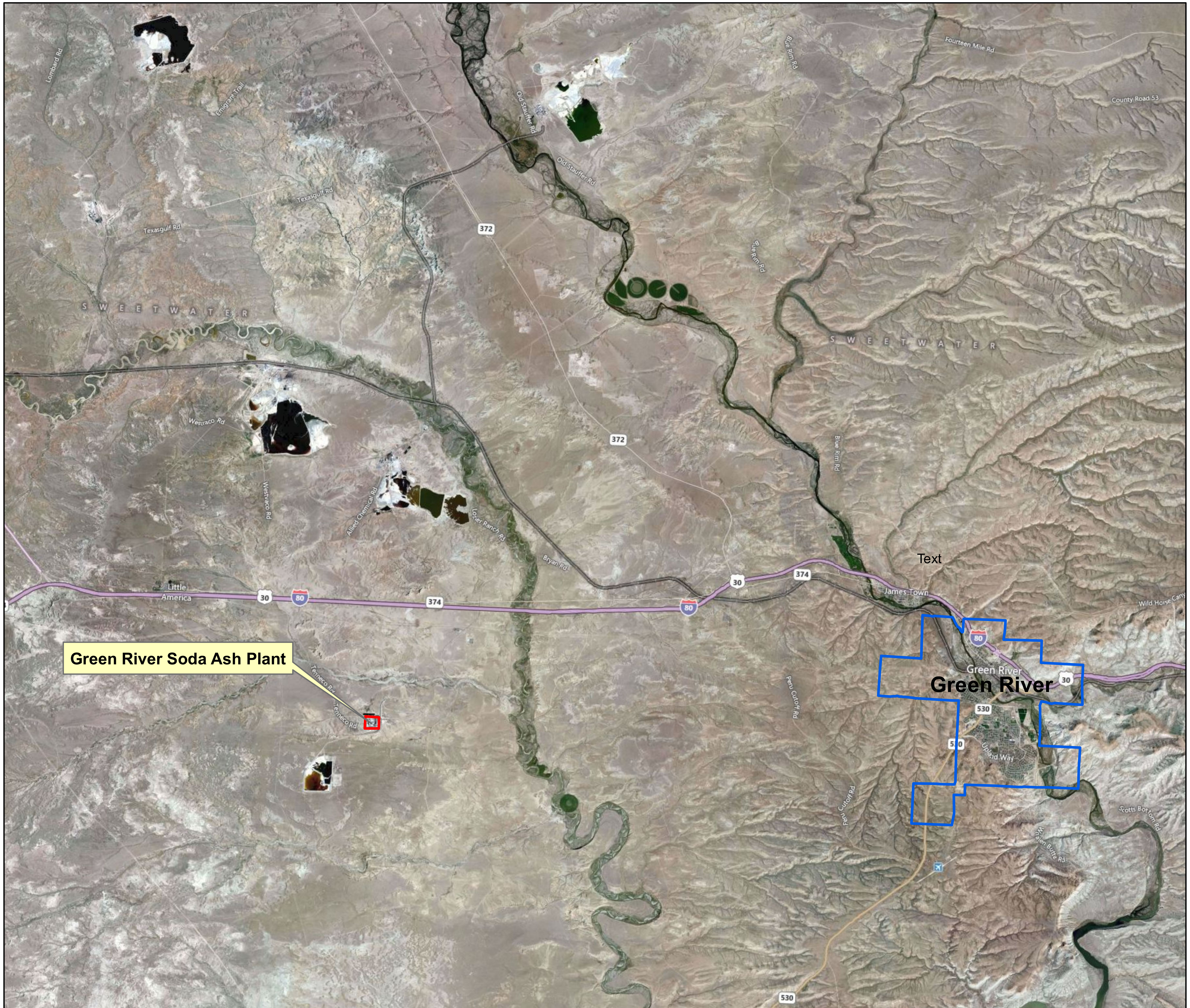
Data Sources:
City Boundary - NAVTEQ (2012);
County Boundary - U.S. Census MAF/TIGER (2010); and
Base - Microsoft Bing web service (2012)

0 5 10 20 Miles

Area Enlarged



EPA United States Environmental Protection Agency REGION 8 serving the states & tribes of Colorado, Montana, Wyoming, Utah, North Dakota & South Dakota



Clean Air Act Federal Prevention of Significant Deterioration (PSD) of Air Quality Permitting for Solvay Soda Ash Joint Venture

Green River Soda Ash Plant

City Boundary

Date: September 16, 2013

Map Projection: UTM, Meters, Zone 13N, NAD83.

Data Sources:

City Boundary - NAVTEQ (2012)

Base - Microsoft Bing web service (2012)

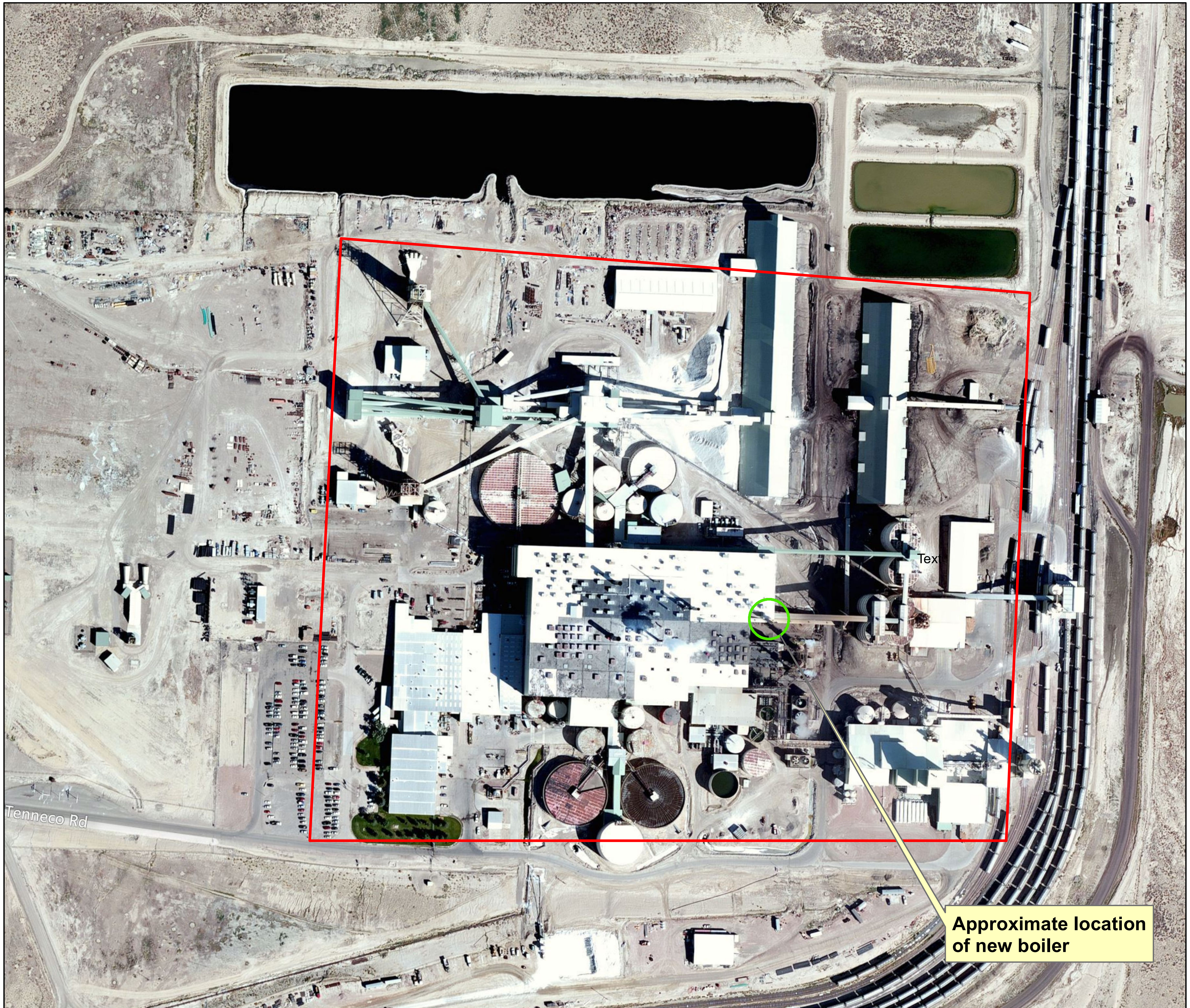
N

0 1.5 3 6 Miles

Area Enlarged

EPA United States Environmental Protection Agency

REGION 8
serving the states & tribes of Colorado, Montana, Wyoming, Utah, North Dakota & South Dakota



Clean Air Act Federal Prevention of Significant Deterioration (PSD) of Air Quality Permitting for Solvay Soda Ash Joint Venture

Green River Soda Ash Plant

Approximate locatiohn of new boiler

Date: September 16, 2013

Map Projection: UTM, Meters, Zone 13N, NAD83.

Data Sources:
Base - Microsoft Bing web service (2012)

N

0 0.03 0.06 0.12 Miles

Area Enlarged

EPA United States Environmental Protection Agency

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Permit #: PSD-WY-000004-2012.001

AIR SCIENCES INC.

DENVER • PORTLAND

PSD Permit Modification Natural Gas Boiler Addition Greenhouse Gas BACT

PREPARED FOR:

SOLVAY SODA ASH JOINT VENTURE GREEN RIVER SODA ASH PLANT

PROJECT NO. 170-12
AUGUST 2012

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Tables

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LIST OF ABBREVIATIONS

ACFM	Actual Cubic Feet per Minute
BACT	Best Available Control Technology
BAE	Baseline Actual Emissions
BLM	Bureau of Land Management
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEM	Continuous Emission Monitor
CFR	Code of Federal Regulations
CH4	Methane
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
DEQ	Wyoming Department of Environmental Quality
EGU	Electric Generation Unit
EPA	The United States Environmental Protection Agency
°f	Degrees Fahrenheit
FGR	Flue Gas Re-circulation
FR	Federal Register
ft	Feet
g	Gram
GHG	Greenhouse Gas
GWP	Global Warming Potential
HFC	Hydrofluorocarbon
HHV	Higher Heating Value
H_2O	Water
hr	Hour
kWh	Kilowatt-hour
lb.	Pound
lb./hr	Pounds per Hour
µ	Micro (10^{-6})
MCR	Manufacturer Capacity Rating
MMBtu	Million British Thermal Units
MT	Metric Tons or Tonnes
N_2O	Nitrous Oxide
NAAQS	National Ambient Air Quality Standards
NO_X	Oxides of Nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review

O_3	Ozone
OFA	Over-Fire Air
PAE	Projected Actual Emissions
PFC	Perfluorocarbon
PM_{10}	Particulate Matter (with aerodynamic diameter $\leq$ 10 micron)
ppb	Parts per Billion
ppm	Parts per Million
PSD	Prevention of Significant Deterioration
psig	pounds per square inch - gauge
PTE	Potential to Emit
RBLC	RACT BACT LEAR Clearinghouse
RH	Relative Humidity
s	Second
SCR	Selective Catalytic Reduction
SF_6	Sulfur Hexafluoride
SO_2	Sulfur Dioxide
tpy	Tons per Year
ULNB	Ultra-Low-NO_X Burner
VOC	Volatile Organic Compound
WAAQS	Wyoming Ambient Air Quality Standards
WI	Water Injection
yr	Year

1.0 INTRODUCTION

Solvay Soda Ash Joint Venture Inc. (Solvay), located 20 miles west of Green River, Wyoming, plans to de-bottleneck its soda ash and related products production circuits. This primarily involves adding a steam boiler, which will be the only new source of air emissions. The de-bottlenecking will include adding a heat exchanger, which will utilize available steam heat for the purpose of speeding up the crystallization processes. The combination will serve to increase both short-term and long-term production while remaining within the previously permitted design rates.

The additional boiler will trigger a PSD-level modification to Solvay's air permit, and as one component of that permitting application, the greenhouse gas (GHG) emissions and related Best Available Control Technologies (BACT) are addressed in this report. The PSD permit application is being prepared for submittal to the Wyoming Department of Environmental Quality (WDEQ). Since Wyoming has not accepted authority for administering the federal PSD rules related to GHGs (40 CFR 52.21), the GHG part of the application, is to be processed by the United States Environmental Protection Agency (U.S. EPA) and is prepared in this separate document for submittal to the U.S. EPA.

Figure 1 shows the Solvay Soda Ash Plant location. Figure 2 provides an aerial photograph of the plant, showing the proposed boiler location, which is to be within the existing physical building perimeter. General information regarding the project and project-relevant contacts is provided below. Table 1 lists the equipment to be added to the plant as part of this proposed action. This listing shows that this will be a simple modification of adding a steam boiler to an existing steam manifold and distribution system and a clear liquor heater which will be a consumer of steam heat with no air emissions.

Project Name:
Natural Gas Boiler Addition - 2012

Applicant, Owner, and Operator:
Solvay Soda Ash Joint Venture
Green River Soda Ash Plant

Physical Location:
NE Quarter, Section 31, Township 18 North, Range 109 West
Sweetwater County, Wyoming

Mailing Address:
Solvay Soda Ash Joint Venture
P. O. Box 1167
Green River, WY 82935

Contact Information:

Responsible Official:	Mr. Ronald O. Hughes	307-875-6500
Permit Contact:	Mr. Tim Brown	307-875-6500

Table 1. Equipment to be Added as Part of Project

Equipment Unit	Type of Emission
Natural Gas-Fueled Boiler	Combustion Emissions
Clear Liquor Pre-Heater	None

Figure 1. Solvay Facility Location on a Regional Scale Map

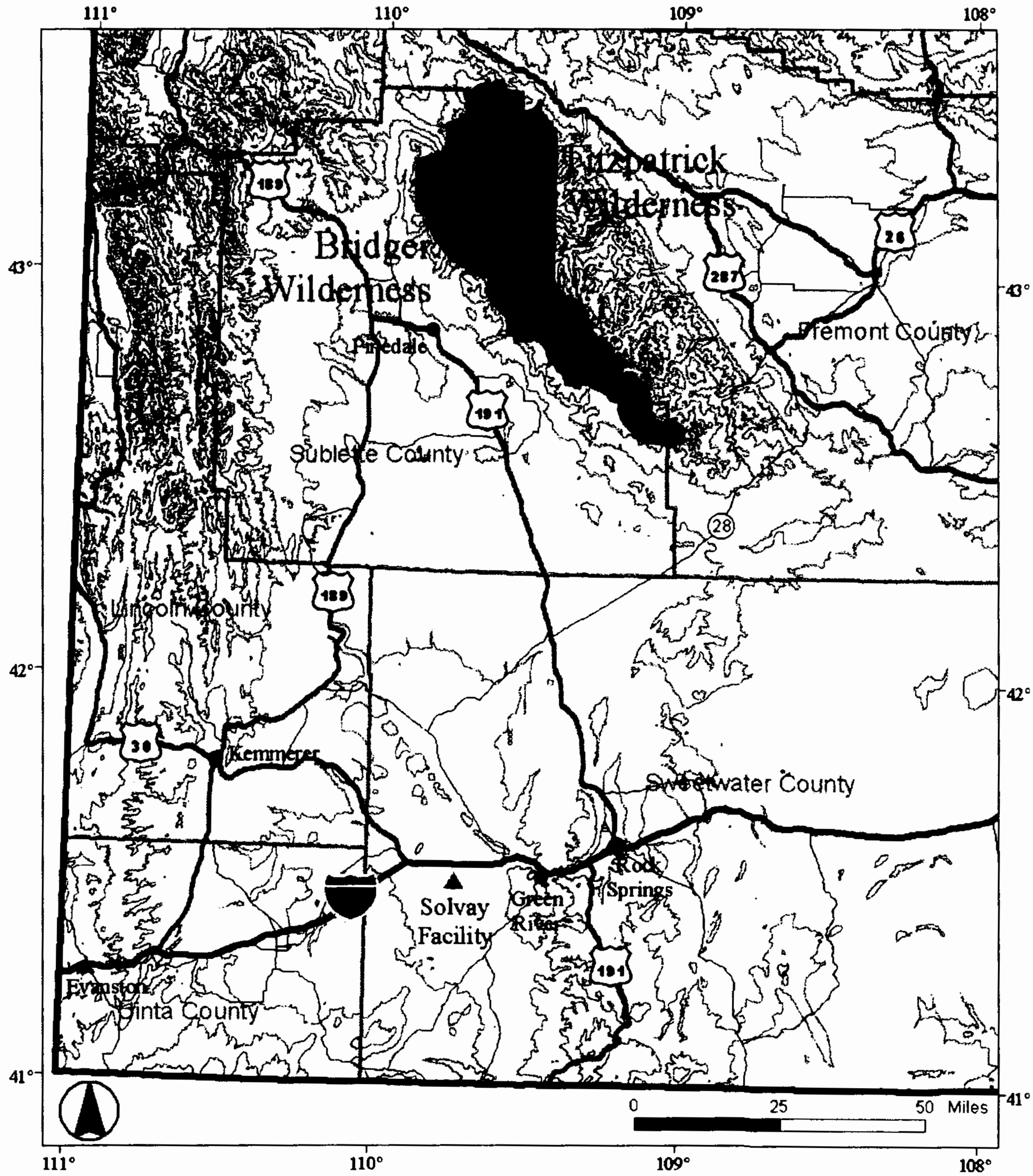
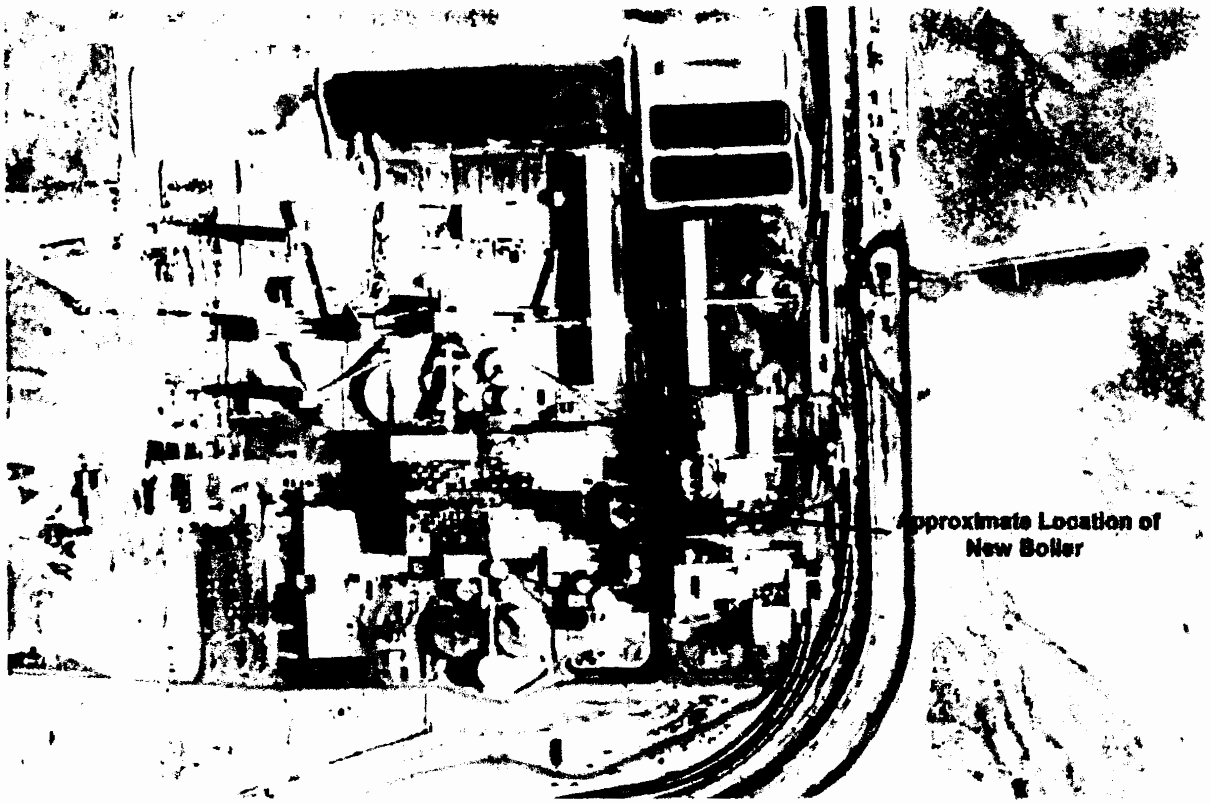


Figure 2. Facility Aerial Photo



Although separately reviewed, the BACT for the criteria pollutants and the BACT for the GHGs must be considered together because one affects the other. The pollutants of interest in the criteria pollutant BACT are primarily nitrogen oxides (NO_X), and secondarily carbon monoxide (CO). Both can have health and environmental effects, so they are important to control. This BACT is for the purpose of minimizing GHGs that have global warming effects. Thus, there needs to be a balance in engineering design to address both criteria pollutant and GHG emissions. Fortunately, to a degree, good design benefits both.

The March 2011 U.S. EPA Guidance (Guidance)[1] for permitting GHG sources is followed for this analysis, and a listing of specific boiler CO_2e (carbon dioxide equivalent) improvements (ICI Boiler Manual)[2] is also largely followed for the BACT recommendation.

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[1] U. S. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, March 2011, EPA-457/B-11-001.

[2] U. S. EPA, Office of Air and Radiation, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers, October 2010.

2.0 DESCRIPTION OF THE SOURCE

The Solvay natural gas boiler will add steam-generating capacity to the two existing coal-fueled boilers so that Solvay will have flexibility to (1) shut any one of the three boilers down for maintenance without curtailing production, and (2) take advantage of the lower-cost fuel between coal and natural gas. The clear liquor preheater will use steam heat to increase the temperature of the clear liquors (with product in solution) upstream of the crystallizers, thereby increasing the evaporation rates and speed of crystallization.

With this de-bottlenecking, Solvay expects to increase annual soda ash production by approximately 14 percent. Steam production is also expected to increase by approximately 14 percent as the two are nearly directly related, but steam production will still be limited to below boiler capacity as there is currently no other host for additional steam consumption. Although steam production will be limited by current soda ash capacity, this permit modification assumes no operational limit on combined steam production, and the additional boiler will be permitted to operate at capacity. In this way, the gas-fueled boiler could run at its maximum while the coal boilers would supplement as needed, or the coal-fueled boilers could operate at their capacity while the gas boiler would supplement the steam demand.

This additional boiler is a water tube package boiler (a Foster Wheeler Model AG 5195, 254 MMBtu boiler) that was installed previously in Garfield County, Colorado at the American Soda facility. It was used from 2000 through May 2004 and then permanently shut down. It is a boiler capable of producing 200,000 lbs. of steam per hour, to be added in parallel to the two 300,000 lbs. per hour coal boilers, increasing plant steam production capacity by 33 percent. As part of the 2003 purchase of the American Soda plant, Solvay owns this boiler. The Foster Wheeler boiler specifications are provided in Appendix A.

Short-term production capacity will not change, although the addition of the heat exchanger will allow short-term actual production to increase and come nearer to capacity. On an annual basis, this additional steam production will enable the plant to continue production during boiler maintenance so there can also be an increase in long-term actual production. Solvay anticipates actual annual soda ash production to increase by 360,000 tons from the current actual level of 2.55 to 2.91 million tons. Depending on the mix of boiler use between coal and gas, the group of boilers' criteria pollutant, and CO_2e, emissions could increase, but not necessarily, as the gas boiler emissions are lower on a per-unit-of-steam-basis than those from the coal boilers. If the gas boiler were to operate at capacity with the coal boilers cut back, boiler emissions of at least NO_x and CO_2e would decrease. Emissions from the other existing fueled sources, which are the calciners and some dryers, could increase with increased production since they operate in series with the steam-heated crystallizers.

The criteria pollutant BACT analysis for the additional boiler concludes that an ultra-low NO_X burner (ULNB) with associated 30 percent flue gas recirculation (FGR) and combustion control instrumentation will be required to minimize NO_X and CO emissions with a guarantee of 9 ppm NO_X and 50 ppm CO (See

Appendix B, Coen Burner bid). The associated instrumentation will include a continuous emission monitor for NO_x and a diluent. Thermal efficiency of this boiler in its initial configuration was estimated by Foster Wheeler at 83.3 percent, shown on page 3 of Appendix A. This compares favorably with the ICI Boiler Manual listing of current-technology natural gas boiler efficiency at 84 percent. Both the initial Foster Wheeler configuration and the ICI Manual configuration assume about 10 percent flue gas recirculation and higher NOx and CO emissions than Solvay is presently proposing. The presently proposed ULNB is associated with up to 30 percent FGR and this higher recirculation has a slight negative effect on thermal efficiency. Solvay's proposed Coen burner with 30 percent FGR is associated with 15 percent excess air, and the IGI Boiler Manual[3] states that with increased excess air over 10 percent, there is a decrease in thermal efficiency. Using the values provided with this statement and assuming a linear relationship of thermal efficiency with excess air, there will be about a one third of a percent efficiency loss due to the ULNB and its related extremely low CO and NOx emissions. So, the currently proposed Solvay boiler configuration will have a thermal efficiency of about 83 percent. Solvay believes that this burner modification and associated combustion control instrumentation represent the design and operational controls of a current-technology boiler with high levels of emission control. Since the boiler is already owned by Solvay and it represents current technology, the cost of replacing the boiler would be high and therefore alternate boiler and burner designs are not considered further in this BACT analysis. The remaining GHG BACT analysis is limited in its focus on efficient heat use and retention.

There will be no alteration of electrical switching and metering, and therefore no emissions of SF_6.

The boiler will be fueled through the Western Gas Pipeline by a spur currently feeding the Solvay plant. So, there will be no installation of a fuel feed line, except within the plant. Solvay will regulate the gas down to approximately 73 psig for plant-wide purposes and further regulate at the burner according to burner manufacturer specifications. If the boiler were to run at 100 percent Manufacturer Capacity Rating (MCR) of 254 MMBtu/hr for 365 days/yr., annual natural gas consumption would be 2,181,412,000 scf/yr or 101,138,000 lb/yr. using a value of 22,000 BTU/lb., or 1020 Btu/SCF as the HHV of natural gas.

Gas piping for the boiler will add 6 valves and 18 flanges[4] in the main service (3 and 4 inches in diameter). There will be no additional fuel-line heaters associated with this boiler installation. Methane emissions from these valves and flanges are estimated using EPA emission factors[5] and these CO_2e emissions are very small in comparison to those from the boiler combustion.

Construction will involve a minimal amount of site preparation since the boiler will be installed within the existing facility, as shown in Figure 2. There will be no additional land clearing or road building. Preparation for the boiler will consist of excavation for the foundation, drilling of caissons, and

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[3] IGI Boiler Manual, page 12, Paragraph 5

[4] E-mail from Ryan Schmidt to Tim Brown, June 12, 2012, Subject Valves and flanges

[5] Per 40 CFR 98, Subpart W, Table W-1A (Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production). Western U.S., Population Emission Factors - All Components, Gas Service; assume all gas emitted as methane to be conservative.

foundation pouring. The boiler will be trucked from Colorado on state highways to Solvay and temporarily stored on site until the foundation is prepared, then placed in final position. Mechanical an electrical work will proceed from there. The foundation excavation is scheduled to begin in the second quarter of 2014 and the project will be completed in the fourth quarter of 2014.

3.0 APPLICABILITY OF PSD REGULATIONS AND TRIGGERING BACT ANALYSIS FOR GHG

The New Source Review analysis for criteria pollutants is performed under Wyoming Air Regulations, (WAQSR) Chapter 6, Section 4 and an application for a PSD permit modification is being submitted to the Wyoming Department of Environmental Quality. That application (the associated emission tables are also provided here in Appendix C) shows that criteria pollutant emissions (NOx, CO, VOCs, and PM) will trigger the PSD New Source Review (NSR) process. The inventory of increased emissions associated with the criteria pollutant application and GHG are calculated on a common spreadsheet so that all operational assumptions are common. Appendix D contains the GHG emissions portion of the spreadsheet and the final column of the third table shows an increase in CO_2e emissions of over 75,000 tons per year. Thus, Under 40 CFR 52.21 (b)(49)(iv)(b) this project is also subject to the federal New Source Review for GHG.

When estimating CO_2e emissions and according to 40CFR 52.21 (b)(49)(ii)(a), six gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride are to be considered, and their GWP is to be estimated according to (ii)(a). The Appendix D emissions estimates are performed accordingly. Because the natural gas boiler combusts sulfur- and fluoride-free fuel, there will be essentially no emissions of hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride so the analysis is limited to estimation of emissions of the first 3 substances.

There are no ambient (or impact) standards for GHGs, and therefore the NSR is limited to control technology review, which in turn consists of a BACT analysis and addressing any New Source Performance Standards (NSPS), found in 40 CFR Part 60, requirements. There are no NSPS promulgated for GHG, although one has been proposed on March 27, 2012 for electric generating units (EGUs), to be described as NSPS Subpart TTTT.

Although not applicable because none of its product is electricity sold to the electric grid, the proposed standard will be equal to or below 1000 lbs. CO_2 / MWh. It is estimated as the sum of all emissions divided by the sum of all electrical and useful thermal energy (CHP) over a 12-month rolling period. None of the Solvay boiler steam is to be used for electricity generation, some of it is to be used for mechanical power drives, but most of it is to be used as heat for an industrial process. Thus, a comparison with this standard can only be hypothetical. An estimate of thermal efficiency is provided here for conversion to electricity at 33 percent and 35 percent[6]. The current potential to emit (PTE) estimate of CO_2 shown in Appendix D is 130,049 tons with a heat input of 2,225,000 MMBtu/yr. (652,000 MWh/yr. energy equivalent). Converting to useable energy output at 33 and 35 percent, the output would be 215,139 MWh and 228,178 MWh respectively. So the CO_2 emissions per unit of energy output would be 1090 lbs./MWh and 1028 lbs./MWh at 33 percent and 35 percent electric production efficiency

[6] http://www.naturalgas.org/overview/uses_eletrical.asp . Typical thermal efficiency range given as 33 to 35 percent.. and ICI Boiler Manual: page 35, given as a typical thermal efficiency for steam boiler

respectively. These emission rates are about 9 percent and 3 percent higher than the proposed NSPS for EGUs.

For the purpose of determining the trigger for a BACT analysis, the Guidance is followed. The first step, from the Guidance Appendix, is to define the source category, which is "a modified source, with the permit to be issued after July 11, 2011", so Appendix D contains the appropriate flow chart. From the existing Solvay Title V permit, it is apparent that the existing source has a PTE of greater than 100,000 tons per year (tpy) of CO_2e and GHG mass greater than 250 tpy. Baseline actual emissions (BAE) of the regulated pollutants and GHG constituents are estimated using the actual emissions between 2006 and 2010 for a CO_2e total of 1,167,598 tpy. Projected actual emissions (PAE) are a combination of emissions from the natural gas boiler operating at capacity, and the existing sources producing an additional 360,000 tpy of product. Appendix D of this report provides the calculations of BAE and PAE for CO_2 and CO_2e.

The explanation of how the emission baseline actual inventories were selected is fully explained in the criteria pollutant BACT analysis, but an abbreviated explanation is provided here. BAE are defined in WAQSR, Chapter 6, Section 4(a) and 40 CFR 52.21 (b)(48)(ii) for an existing emissions unit. BAE means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit PSD application is received by WDEQ, whichever is earlier. For a regulated PSD pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used for each regulated PSD pollutant. To calculate BAE for the existing project sources, Solvay utilized the latest available five years (2006 to 2010) of facility-wide actual emissions information. For GHG, the period 2007 and 2008 was selected because these years represented the highest BAE from 2006 to 2010.

PAE are defined in WAQSR, Chapter 6, Section 4(a) and 40 CFR 52.21(b)(41)(i) in the federal PSD regulations for both new and existing units and means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated PSD pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project. In lieu of calculating PAE, the emissions for a unit may be calculated as the PTE for the unit. Solvay has the flexibility of operating the boiler at its MCR so its PAE is based on capacity operation. The existing sources PAE is evaluated at a production increase of 360,000 tons per year of product.

The analysis for GHG contributors is different from the analysis for the criteria pollutants only in that the emissions from the "contemporaneous changes" are not addressed for the GHGs. This is because the baseline GHGs are not defined and their contribution will only add a minor amount of emissions, which will not affect the major GHG source categorization. Table 2 shows that this modification will have GHG global warming potential (GWP) emissions of at least 130,000 tpy, well over the 75,000 tpy threshold, and the GHG mass of emissions will be greater than zero. The netting, considering the gas boiler (including valve and connector fugitives) and debottlenecked process and combustion emissions, is estimated, as shown in Appendix D, and the results are provided in Table 3. The mass of GHG will be greater than zero and the CO_2e will be greater than 75,000 tpy. Consequently, following the Guideline Appendix D flowchart, this modification will be a major GHG source and subject to GHG BACT.

Table 2. Boiler Greenhouse Gas Annual Emissions*

Component	Mass Emission (tons/yr)	GHG GWP (multiplier)	GHG CO_2e (tons/yr)
CO_2	130,041	1	130,041
N_2O	0.25	310	76
CH_4	6.97	21	146
HFCs & PFCs	0	various	0
SF_6	0	23,900	0
Total	130,049		130,263

* Gas-fueled boiler operating at design rate for 8,760 hours per year and including fugitive emissions from valves and connectors.

Table 3. Net Solvay Plant Increase in Greenhouse Gas Annual Emissions with Additional Boiler and Associated Existing Unit Use Increases *

Component	Mass Emission (tons/yr)	GHG GWP (multiplier)	GHG CO_2e (tons/yr)
CO_2	493,305	1	493,305
N2O	1.3	310	402
CH4	14.7	21	309
HFCs & PFCs	0	various	0
SF6	0	23,900	0
Total	493,321		494,015

* Gas-fueled boiler operating at design rate for 8,760 hours per year and including fugitive emissions from valves and connectors.

4.0 BACT SELECTION PROCESS

Section III of the Guidline for permitting of GHG is followed here for the BACT analysis. The scope of this permitting effort and BACT analysis is limited to the one used-gas-fueled boiler added to an existing facility, since the only equipment change regarding air emissions is the added boiler. The five-step process is followed and addresses only GHG emissions. Since the boiler will be natural-gas-fueled, the overwhelming pollutant of interest is CO_2. There will be negligible emissions of the other GHGs. Of the negligible GHG constituents, only methane and nitrous oxide are generally recognized as constituents of natural gas combustion so these are also quantified.

Natural gas is essentially methane with small quantities of the higher carbon chain hydrocarbons (ethane, propane, butane, etc.) and is the cleanest burning hydrocarbon fuel, especially with regard to GHG emissions, so consideration of alternate fuels to decrease GHG emissions is irrelevant in this BACT analysis. Furthermore, because of the high level of excess air (15 percent) associated with the proposed NOx and CO BACT controls, burner fuel slip is virtually eliminated. If there were to be any incomplete combustion, it would be sensed by the CO CEM used to track compliance with the anticipated CO emission limit. This BACT analysis is reduced to one of minimizing fuel consumption per unit of useable heat produced. Stated another way, this analysis focuses on maximizing the thermal efficiency of the boiler and its associated equipment and minimizing heat loss as waste.

Appendix F of the Guidance is referenced as it provides an example BACT analysis for a 250 MMBtu/hr gas-fueled boiler. This BACT process generally follows the process designed for the criteria pollutants, but for GHG minimization, the process for this boiler becomes an efficiency-improvement process, layered on top of a NO_X/CO BACT evaluation. The technologies discussed below are related to energy efficiency improvements and associated energy, environmental, and economic impacts.

The BACT analysis is a five-step process:

Step 1: Identify all available control technologies.

Step 2: Eliminate technically infeasible options.

Step 3: Rank remaining control technologies.

Step 4: Evaluate most effective controls and document results.

Step 5: Select the BACT.

4.1 Step 1: Identify all available control technologies

Solvay proposes to add steam-generating capacity to an existing steam manifold and consumption system using an existing, owned, and available boiler; therefore, use of any other heat-generating equipment and processes would fundamentally redefine the proposed source. Because of this, no alternate means of generating additional steam are considered.

The gas-fueled boiler is being added to the Solvay plant to supplement the steam provided by existing coal-fueled boilers, but it could also be used as a base load while varying the steam production of the coal-fueled boilers to meet capacity. In this way, the CO_2e would be reduced because the GWP per unit of heat from coal is higher than the CO_2e for heat from natural gas (94 kg CO_2/MMBtu v 53 kg CO_2/MMBtu[7]). Solvay asserts that the flexibility to use the boilers as best meets the needs of the plant is its choice and that the BACT analysis does not extend to this level of controlling the mix of boiler usage.

Technology related to maximizing steam boiler energy efficiency is provided in the ICI Boiler Manual, which addresses feasible efficiency-increase technologies as a surrogate for CO_2 control technologies for steam boilers. At 254 MMBtu per hour, the Solvay boiler fits well within the class of ICI boilers addressed. Table 4 lists the entries as feasible options for maximizing energy efficiency. As Table 4 illustrates, the methods of increasing thermal efficiency from a boiler can be grouped as: 1) Efficient design of boiler and associated steam delivery equipment, 2) Efficient operation of equipment, 3) Good maintenance, and 4) Other measures.

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[7] Ibid.

Table 4. Possible Energy Efficiency Improving Methods, Feasibility, and Whether Included as BACT

Method	Feasible?	Reason	Included as BACT?	Reason
Efficient design of boiler and associated steam delivery equipment				
High-efficiency burner	Yes		Yes	New Coen Ultra-Low NO_X Burner (ULNB) to be added
Refractory material selection	Yes		Yes	Best available already included with boiler[8]
Use of an economizer	Yes		Yes	Economizer comes with boiler package. Used to heat boiler feed water. Economizer reduces exhaust to 320°F
Blowdown heat recovery	Yes		Yes	Blowdown (steam with high solids content) is sent to the flash tank where 300 lb steam flashes to 35 lb steam and condensate
Condensate recovery for boiler reuse	Yes		Yes	Maximum amount the steam circuit will accept based on water quality requirements. All condensate is recovered for use in the plant
Combustion air pre-heater	Yes		Yes	Combustion air is drawn from the process building roof line which is approximately 20 F warmer than building ground level air, and also serves as crude air conditioning by drawing into the building cooler ambient air
Increase the amount of boiler insulation	Yes		Yes	Boiler designed for 3", feasibility decreases with thickness. Solvay agrees to install at 4 inches. See Appendix E
Increase the amount of refractory lining	No	A boiler performance function. Meets current design requirements[9]		
Efficient operation of the boiler and related steam distribution equipment				
Energy management systems - use and production of steam	Yes		Yes	Boiler will be connected into the current steam management system and will be controlled by Solvay's current energy management system
Good O&M practices - tuning, oxygen trim/cleaning of burner and oxygen feeds	Yes		Yes	Written O&M practices includes these

[8] Telecom, Tony Hawranko of Foster Wheeler with Ryan Schmidt of Solvay, May 8th, 2012. Available changes in refractory material would make negligible difference in heat transfer.

[9] Ibid. Increase in amount of refractory material would require boiler redesign.

Method	Feasible?	Reason	Included as BACT?	Reason
Boiler instrumentation & controls	Yes		Yes	The boiler package includes I&C. Additional control is included with ULNB to meet NO_X & CO emission limits
Good maintenance				
Steam-line maintenance (including integrity of insulation)	Yes		Yes	Scaling to be controlled with anti-scalant additive. Pipes to be visually checked at least quarterly and insulation replaced as needed
Minimization of air infiltration	No	Positive pressure boiler		
Minimization of gas-side heat transfer surface deposits	No	Not relevant to gas firing		
Minimize steam trap leaks	Yes		Yes	Inspected and repaired at least annually
Other Measures				
Turbine shaft power extracted from high-pressure steam	Yes		Yes	Included in existing steam circuit. There are 9 turbines powering 4 ducted fans and 5 pumps. With more continuous steam supply and less production "down time," turbines will be used more continuously over the year. Turbines eliminate use of electrical power
Carbon Sequestration	No	Sinks Not Available	No	Unreasonable cost

4.2 Step 2: Eliminate technically infeasible options

The last of the "Other Measures" options is Carbon Capture and Storage (sequestration) (CCS) is addressed first. It is discussed in the Guideline as an add-on control technology and should be considered for:

> *....facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).* [10]

Since the Solvay Green River Facility is not one of these types of facilities, and furthermore, is relatively small at 254 MMBtu/hr., the Guideline states that CCS is expected to be not feasible as an available control option. Nevertheless, EPA requested that Solvay provide an evaluation of the economic feasibility of CCS as part of Step 4 of the natural gas boiler addition BACT analysis.

All the Table 4 methods are feasible except those related to multiple fuel burning, boiler/burner design, and CCS. Slag formation and cleaning of surface deposits are related only to coal combustion, so they are not addressed for this boiler since it will be natural-gas fueled. The quantity and placement of refractory material is part of the boiler design and determined by the manufacturer for this boiler and should not be altered. The ultra-low NO_X burner (ULNB) package includes combustion monitoring and controls; it comes with a CO and NO_X emission guarantee. The ULNB package likely serves to maximize the boiler thermal efficiency, but it cannot be altered for GHG purposes without voiding the guarantee.

The Report of the Interagency Task Force on Carbon Capture and Storage (Task Force Report)[11] lists an application of CCS at the Searles Valley Minerals soda ash plant in Trona, California. It is used as part of the process and CO_2 is consumed on site unlike Solvay where the natural soda ash process converts trona ore (sodium sesquicarbonate dihydrate [Na_2CO_3-$NaHCO_3$-$2H_2O$]) to soda ash (Na_2CO_3) giving off CO_2 and H_2O in the decomposition process. The Solvay Green River Facility process does not require the addition of CO_2 to convert sodium bicarbonate ($NaHCO_3$) in a brine solution into soda ash as is needed in the Searles Valley process[12]. Therefore it is not feasible as a component of the Solvay process.

4.3 Steps 3 & 4: Rank remaining control technologies and evaluate most effective controls

Regarding selection of a high efficiency boiler as part of the GHG BACT process, since Solvay already owns the boiler, as part of the purchase of another soda ash plant in 2004; the boiler is available at no cost

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[10] Guidance, page 32, paragraph 2.

[11] Report of the Interagency Task Force on Carbon Capture and Storage, http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf, p 31.

[12] Garrett, Donald E., Natural Soda Occurrences, Processing, and Use, Copyright 1992 by Van Nostrand Reinhold

to Solvay. Furthermore, in comparing the Solvay boiler thermal efficiency, discussed in Section 2.0, Description of the Source, with typical new boilers, the Solvay boiler is similar in efficiency, and is already owned, so without further cost analyses, it is obvious that cost of other designs would be large and there is no need to further evaluate other designs.

Solvay is implementing all of the feasible methods of efficiency improvement. In addition to enclosing the boiler within a building, which will provide protection from the wind and extreme winter temperatures, the amount of exterior boiler insulation is addressed. The thickness of insulation is evaluated as a balance between emission-control-effectiveness and practicality.

The boiler manufacturer recommends a minimum of 3 inches of insulation based on safety considerations and has designed the boiler, including its valves, fittings and sleeves, for 3 inches of insulation. With greater insulation thickness the access to and maintenance from the exterior becomes more difficult. Moreover, the volume into which this boiler is to be installed is limited and insulation thickness will consume volume needed for movement around the boiler. Solvay has priced the cost of 3, 4, 5, and 6 inches of insulation, using a 20-year remaining life of boiler, natural gas cost savings of $2.34 per thousand cubic feet, and 8760 hours per year operation at 254 MMBtu/hr (which is at PTE). These costs are summarized in Table 5 and the calculations and assumptions are provided in Appendix E. The analysis indicates that the cost to Solvay of installing insulation spread evenly over 20 years, and including fuel savings from additional insulation is about neutral, considering the cost savings of boiler fuel all the way to 6 inches of insulation. Thus, from this simplistic analysis it makes economic sense to install more insulation and there is no natural limit. But as insulation increases, so do issues with buried valves, fittings, and sleeves, and the inconvenience of maintenance is not a quantifiable cost. Solvay proposes to use the diminishing benefit in avoided CO_2e value with thickness to establish a BACT limit. An increase from 3 to 4 inches is associated with a 10.4 tpy benefit in avoided CO2e emissions, and carries a benefit of $257 per year. An increase from 4 to 5 inches is associated with a 6.5 tpy decrease in CO2e, which is 0.005 percent of the 130,000 tons per year total potential to emit (PTE) and essentially a negligible decrease. Insulation increase to 6 inches is associated with an even smaller CO_2e benefit. Since the boiler will never operate at PTE but insulation cost is fixed, the actual benefit should be lower. Solvay believes that improvements in CO_2e beyond 4 inches of insulation are essentially negligible and therefore, not worth the additional maintenance difficulties and loss of volume surrounding the boiler. Therefore, Solvay proposes 4 inches of insulation as BACT.

Table 5. Incremental costs for added boiler insulation

	Increase 3" to 4"	Increase 4" to 5"	Increase 5" to 6"	Increase 3" to 6"
Decrease in CO_2e	10.4 tons/yr	6.5 tons/yr	4.4 tons/yr	21.3 tons/yr
Increase in insulation cost	$3,036	$9,994	$3.036	$16,066
Annualized cost of insulation and fuel savings at PTE	- $257/yr	$146/yr	- $51/yr	- $192/yr
Cost of CO_2e eliminated, fuel savings included	- $25/ton-yr	$ 23/ton-yr	- $12/ton-yr	- $9/ton-yr

Review of the cost for CCS: For this analysis Solvay relies primarily on the Task Force report, prepared by 14 Executive Departments and Federal Agencies.

From that report, the cost for CCS is segmented into:

1) Cost of capture and compression of the CO_2,

2) Transport of the CO_2 and

3) Storage in geologic formations.

This analysis is approximate and addresses only the costs for capture and compression since it is the bulk of the CCS cost[13]. Furthermore, the bulk of their cost data is from coal-fueled power plants, likely because there is a higher concentration of CO_2 in the flue gas than for natural gas[14], 13 to 15 percent for coal compared to 3 to 4 percent for natural gas, and it is more efficient to capture a constituent from a higher concentration flue gas. Nevertheless, without attaching an increase in cost on a per unit of CO_2 controlled basis, the cost for retrofit of a capture system and compression will be higher for natural gas fueling than for coal fueling of the boiler. From figure III-I[15], the cost of the cost of CO_2 removal in a retrofit, post-construction circumstance, such as for Solvay, but for a coal-fueled boiler is listed at $103 per tonne[16] ($94 per ton). Since the Solvay boiler is smaller and gas fueled (CO_2 per unit of heat is much lower) the avoided cost per tonne of CO_2 removal will be much higher than $103 per tonne. Although not

[13] Task Force Report, p 27, Section III, "Approximately 70–90 percent of that cost is associated with capture and compression."

[14] Task Force Report, p 29, "A high volume of gas must be treated because the CO_2 is dilute (13 to 15 percent by volume in coal-fired systems, three to four percent in natural-gas-fired systems"

[15] Task Force Report, p 34, right end, green bar

[16] The Federal GHG Reporting Rule requires annual emissions to be reported in metric tons (MT) or tonnes.

quantified, it is likely to be an avoided cost well above $114 per tonne ($104 per ton) CO_2 captured, which is the highest avoided cost of all configurations of power plants. The cost for retrofit of CCS is therefore considered by Solvay to be an unreasonably high cost and therefore it is eliminated as a BACT option.

4.4 Step 5: Select BACT

Solvay commits to installation or incorporation of the listed efficiency enhancements provided in Table 4 as included in the GHG BACT requirements, including use of 4 inches of boiler insulation.

5.0 PROPOSED CO_2e EMISSIONS LIMITS FOR COMPLIANCE DEMONSTRATION

The maximum annual CO_2e emissions are proposed to be the emissions using the boiler Manufacturer Capacity Rating (MCR) which is 254 MMBtu/hr, boiler operation for 365 days/yr., and nominal natural gas quality emissions provided by EPA in 40 CFR Part 98, Subpart C, Table C-1. That nominal value is a CO_2e emission factor of 117 lb/MMBtu. This estimation calculation is shown in Appendix D of this report and results in an annual emission limit of 130,263 tons per year (118,173 MT per year)

The short-term (hourly) CO_2e limit will be in the form of a mass of CO_2e per unit of energy input to the boiler and is derived from a consideration of the variability in fuel constituents. Pipeline gas is primarily composed of methane, but can have varying percentages of the hydrocarbon constituents (methane, ethane, propane, butane, pentane and hexane, etc) and also varying percentages of CO_2 among other passive constituents. The boiler manufacturer provided an estimate of the maximum heat content pipeline fuel that the boiler could experience in NW Colorado and this fuel analysis is presented on page 2 of Appendix A. The CO_2 emissions associated with this gas composition are estimated on the final page of Appendix D, using the constituent-specific CO_2 emissions per unit mass of the constituent and assembling these according to the quantity of the constituent in that fuel analysis. The CH_4 and N_2O components in the exhaust are expected to be approximately the same as for nominal natural gas and these fixed factors are added to the measured CO_2 to determine the total CO_2e short-term emission limit. These factors are 0.05 and 0.07 lb/MMBtu respectively. The CO_2 measurement will be by CEM for exhaust concentration and associated with a continuously measured flow rate using Equation C-6 of 40 CFR Part 98.33 (a)(4)(ii). The Solvay short-term limit by this method is 125.3 lb CO_2e per MMBtu heat input. This is 7 percent higher than the nominal pipeline natural gas value of 116.9 lb CO_2e per MMBtu.

For purposes of demonstrating compliance on a short-term basis, a boiler heat input is needed. This will come from measurement of the volume of fuel consumed by the boiler and coupling it with a Solvay-monitored heat content. Thus, there are three independent measurements being made using different plant control systems, CO_2 concentration, and exhaust flow rate from emissions monitoring, and boiler heat input from process controls. Solvay believes that the shortest time interval over which this will be a meaningful calculation would be 24 hours, using hourly averaged or totaled measurements. Hourly calculations would likely contain inconsistencies because all the measurements would not have been collected at the same time, but more importantly, Solvay expects some hysteresis in the furnace response to fuel feed and probably also with the CO_2 and flow rate monitors, so that the three may not track hour by hour. Therefore Solvay requests that the short-term CO_2 measurement be tracked on a 24-hour totalized basis. The estimate of CO_2e emissions per unit of heat input will be calculated and compared with the compliance limit every calendar day.

6.0 SUGGESTED BACT COMPLIANCE DEMONSTRATION

Solvay proposes the following demonstrations of the proposed BACT commitments:

1) Agreement to include with the boiler installation:

   - ULNB
   - Boiler insulation at 4 inches
   - In-stack economizer to preheat boiler water
   - Blowdown flash tank
   - Ducting for combustion air to be drawn from process building roof line
   - Integration of this boiler into the existing steam production system in parallel with the coal-fueled boilers
   - CO_2 monitoring with CEM

2) Agreement to incorporate into its maintenance and operations practices:

   - Maximized condensate recovery
   - Scheduled inspections of steam lines
   - Use of an anti-scalant agent in the boiler water

3) Demonstration of good operating and maintenance practices by meeting the CO and NO_X emission limits: this is to be a separate requirement of the air permit, and demonstration does not need to be duplicated for the GHG BACT.

4) The long and short-term emission limits for CO_2e emissions will be constructed as discussed in Section 5. Proposed limits are 130,263 tons per year (118,173 tonnes per year), and 125.3 lb per MMBtu, (HHV) respectively.

7.0 ENDANGERED SPECIES ACT AND NATIONAL HISTORIC PRESERVATION ACT (SHPO) DISCUSSIONS

A US Fish and Wildlife Service consultation on threatened and endangered species report and listing for this project is provided in Appendix F. The entire Solvay project will be contained within the existing facility and therefore there should be no additional impact to threatened and endangered species.

Solvay's existing species protection includes a waterfowl protection plan, not included here, but available upon request. They abide by the Avian Protection Plan (APP) Guidelines that were prepared by the Edison Electric Institute's Avian Power Line Interaction Committee (APLIC) and The U.S. Fish and Wildlife Service (USFWS).

Per discussions in a June 18, 2012 meeting between USEPA and Solvay, Solvay has performed a survey to determine the nearest sites listed in the National Register of Historic Places relative to the Solvay facility. The National Park Service (NPS) provides a spatial mapping coverage of historic properties listed in the National Register which can be overlaid on Google Earth™ maps.[17] Figure 3 is a map of the nearest historic properties to the Solvay facility based on this NPS dataset. The nearest historic property to the Solvay facility is a property referred to as Granger Station which is located approximately 20 kilometers to the northwest of the facility. In addition, there is a historic property located further to the north (29 kilometers from Solvay) and there are three properties located to the east in the town of Green River (24 kilometers Solvay).

With the installation of this natural gas boiler, there are no anticipated social or economic impacts beyond the plant site. Air quality impacts to these properties will be well below the primary or secondary NAAQS and should have no effect on them.

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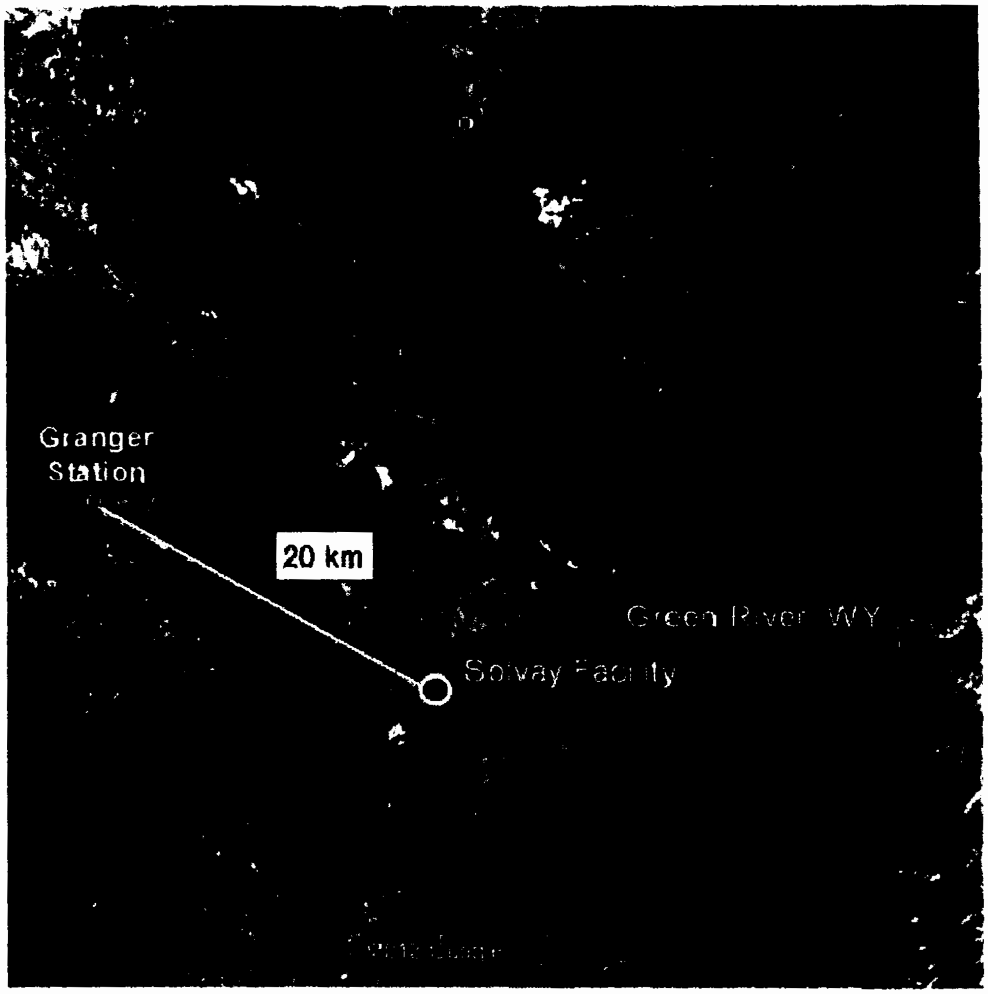
[17] National Park Service webpage: http://nrhp.focus.nps.gov/natreg/docs/Download.html#spatial

Figure 3. Map of Historic Places in the Vicinity of the Solvay Facility



Appendix A: Foster Wheeler Boiler Specifications

EQUIPMENT DATA SHEETS

Equipment Name: Boiler Package	Equipment No.: 81-BO-001 / 002
Operating and Design Conditions	
Minimum Boiler Design Parameters	
Steam Flow -Capacity, lb/hr, each	200,000 lb/hr
-Temperatue, °F	435
-Pressure, psig	350
Blowdown	6450 lb/hr ⚠1
Automatic Turndown Required	25% ⚠1
Return Condensate -Flow, lb/hr ⚠1	200,000
-Temperature, °F	199
Makeup Water -Flow, lb/h	6450 ⚠1
-Temperature, °F	199 ⚠1
-Pressure, psig	25
-Analysis	
-Total dissolved solids	Negligible ⚠1
-Hardness	0 ⚠1
-Conductivity	
-Silica	Negligible ⚠1
-Free or combined CO_2	
Stack Emissions Design Parameters	
-Maximum allowable NO_x	0.035 Lbs / MMBTU (HHV) ⚠2
-Maximum allowable CO	100 ppm

Note to the Bidder:
Bidder is requested to confirm the data filled in the right hand column and fill in any blank lines as completely as possible.
Please type or print and stay within the lined area.

(The information provided in these data pages (1-5) is to be considered preliminary and subject to final contract review)

EQUIPMENT DATA SHEETS

Page 2 of 5

Equipment Name: **Boiler Package**	Equipment No.: **81-BO-001 / 002**		
Operating and Design Conditions (cont'd.)			
Equipment Location	Indoors at Elev. 6600 FASL		
Duty	Continuous		
Natural Gas (At various heating values supplied)	Lowest	Highest	Intermediate
Gross-Heating value, BTU/scf		1064.1	
-Net heating value, BTU/scf		961.0	
(dry basis @ 14.73 psia & 60 °F)			
-Specific gravity (dry basis)		0.61	
-Composition, Volume %			
-Carbon dioxide		2.47	
-Nitrogen		0.61	
-Methane		90.45	
-Ethane		4.07	
-Propane		1.39	
-Iso Butane		0.24	
-Normal Butane		0.27	
-Iso Pentane		0.13	
-Normal Pentane		0.10	
-Hexane		0.24	
-Helium		0.03	
-Sulfur (gr./100 scf)			

Note to the Bidder:
Bidder is requested to confirm the data filled in the right hand column and fill in any blank lines as completely as possible.
Please type or print and stay within the lined area.

EQUIPMENT DATA SHEETS

Equipment Name: **Boiler Package**	Equipment No.: **81-BO-001/ 002**	
Number-required/operating/standby	2/2/0	
Vendor	Foster Wheeler ⚠	
Manufacturer	Foster Wheeler ⚠	
Model No.	AG-5195 ⚠	
Manufacturer Location	St. Catharines, Ontario ⚠	
Heat Input (Max), MMBTU/hr ⚠	250 ⚠	
System Performance	100% condensate	100% make up
Hot Water Flow -Capacity, lbs./hr.	215,000 ⚠	215,000 ⚠
-Temperature, °F	240 ⚠	240 ⚠
-Pressure, psig	395 ⚠	395 ⚠
Turndown Capacity	10:1	
Efficiency (Predicted) ⚠	83.2921 ⚠	
Utility requirements		
-Electrical, kW/V-ph-Hz		
-Plant air, scfm @ psig		
-Instrument air, scfm @ psig		
-Low pressure steam, lb/hr @ psig		
-Cooling water, gpm @ °F		
-Natural gas, lb/hr @ psig ⚠	11,384 (based on 0% blowdown) ⚠	
-Natural gas, mm BTU/hr.,	249.8 ⚠	
Flue gas		
-Volume, acfm	80,115 ⚠	
-Temperature, °F	320 ⚠	
-Composition:		
O_2, %	2.827 ⚠	
Co_2, %	13.591 ⚠	
H_2O, %	11.581 ⚠	
N_2, %	72.000 ⚠	

Note to the Bidder:
Bidder is requested to fill in the right hand column as completely as possible.
Please type or print and stay within the lined area.

EQUIPMENT DATA SHEETS

Equipment Name: **Boiler Package**	Equipment No.: **81-BO-001 / 002**
Boiler	Equipment No.: 81-BO-001 / 002
-Type	"D" Type Model AG-5195
-Steam drum size	54" ID, 39' Length
-Mud drum size	24" ID, 39' Length
-Material of water tubes	SA-178
-Diameter of tubes/wall thickness	2½" / 0.135" and 2" / 0.105" △2
-Overall dimensions, ft.-in.	LxWxH – 48' x 13'-4" x 17'-9"
-Wt of boiler, lbs	180,000
-Total effective heating surface, ft^2 △2	16,490 △2
-Furnace volume, cu ft	3375 △1
Boiler Burner	
-Manufacturer/Model	Coen Company / DAF △3
-No. of Burners/Capacity per burner	1 x 208,500 lb/hr
-Description	
Boiler Combustion Air Fan	Equipment No.: 81-FN-031 / 032
-Manufacturer	Howden Fans △1
-Model	1085BA97 △1
-Capacity, acfm @ in. H_2O	88,141 @ 27.68" WC
-Material casing and wheel	
-Motor hp	600 △2
Economizer	Equipment No.: 81-HR-001 / 002
-Water capacity, lbs/hr	208,500
-Water inlet temperature, °F	240
-Water outlet temperature, °F	339
-Pressure drop, psi	6
-Effective heating surface, ft^2	16,484 △1

Note to the Bidder:
Bidder is requested to fill in the right hand column as completely as possible.
Please type or print and stay within the lined area.

EQUIPMENT DATA SHEETS

Equipment Name: **Boiler Package**	Equipment No.: **81-BO-001 / 002**
Deaerator	Equipment No.: 81-DE-001/002
-Manufacturer/Model No.	Kansas City Deaerator
-Size of Tank	8'-6" Diameter, 21' Length
-Materials/thickness, in.	0.25
-Operating conditions -Pressure, psig	10
-Temperature, °F	240
-Design conditions -Pressure, psig	30
-Temperature, °F	410
-Residual O_2 in effluent, mg/l	0.005
-Steam flow, Lb/h	17,000
Boiler Feedwater Pumps	Equipment Nos.: 81-PP-098A thru C
-Manufacturer/Model No.	Carver / WKM-80
-Capacity and pressure, gpm @ psig	245,000 lb/hr @ 500 psi
-Materials of Construction	D.I. / C.I.
-Motor hp	250
Boiler Stack	One stack per boiler
-Diameter & Height, feet	5'-9 3/4" Diameter, 50-ft overall
-Materials of Construction	Carbon Steel
-Nozzles Provided	Two (2) 4" flanged sampling ports
Chemical Injection Package	Equipment No.: 81-WT-007/008/009/010
-Manufacturer/Model No.	Neptune
-Size of Tank	200 gallons each
-Materials/thickness, in.	316SS
-Chemicals Used	Sulfite, Phosphate
-Pump Capacity & Pressure	12 gal/hr

Note to the Bidder:
Bidder is requested to fill in the right hand column as completely as possible.
Please type or print and stay within the lined area.

Appendix B: Coen Burner Bid

Phil Hoffmann

From: **Wieszczyk, Wayne** <wwieszczyk@coen.com>
Date: Fri, May 4, 2012 at 11:34 AM
Subject: RE: Solvay project: Further questions regarding 9ppm burner; Coen #201202-24271-A
To: "Schmidt, Ryan" <ryan.schmidt@solvay.com>
Cc: North Associates <northassociates@yahoo.com>, "Ingvarson, Lyall" <lyall.ingvarson@coen.com>

Ryan,

Coen is pleased to offer the following information per your request.

1) Coen can offer 50 PPM CO along with the 9 PPM NOx at 100% MCR with 30% FGR and 15% EA. The CO will be guaranteed from 25-100% MCR. The only condition we would be concerned with is that the boiler furnace wall should be seal-welded to help assure no CO bypassing. If the wall is not sealed, Coen would recommend a CO test port at the rear of the furnace to allow us to confirm the CO at the rear vs. the stack during start-up if this became an issue.

2) The products of combustion are listed below based on 100% MCR (253.77 mmbtu/hr) and 30% FGR and 15$% excess air.

Combustion Products

	vol%, wet	vol%, dry	scfm	mass%, wet	mass%, dry	lb/hr	MW
CO_2	8.53%	10.19%	4352	13.43%	15.01%	29755	[redacted]
H_2O	16.36%	[redacted]	8351	10.55%	[redacted]	23374	[redacted]
O_2	2.51%	**3.00%**	1279	2.87%	3.21%	6359	[redacted]
N_2	71.75%	85.79%	36622	71.93%	80.41%	159378	[redacted]
Ar	0.86%	1.02%	437	1.22%	1.37%	2713	[redacted]
SO_2	0.00%	0.00%	0	0.00%	0.00%	0	[redacted]

1) The following estimated temperate per your request for NG

ADFT of NG = 3,391 deg F

Flue Gas Temperature downstream of the economizer = 350 deg F

Flue Gas Temperature in the stack = ~350 deg F

If you need any further information, please feel free to contact us anytime.

Regards,

Wayne A. Wieszczyk

Sr. Application Engineer

Boiler Burner Group

Coen Company Inc.

2151 River Plaza Dr, Suite 200

Sacramento, CA 95833

COEN®
COEN COMPANY, INC.

Coen® Ultra Low NOx Burner Package to meet 9 PPM (Coen File D-13384-1-000)

SUBMITTED TO

Mr. Mike Ganskop
Solvay Chemicals

FOR

Solvay Chemicals
Green River, Wyoming

Proposal Number:	201202-24271-A R1
Application Engineer:	Wayne A. Wieszczyk
Tel:	1 (530) 668-2128
Email:	wayne.wieszczyk@coen.com
Date Prepared:	March 30, 2012

HAMWORTHY
PEABODY

TODD

PROPOSAL CONTENTS

1.0 Overview

Rev. 1 Revise proposal for Ultra Low NOx burner option to meet 9 PPM NOx.

Solvay Chemicals has requested Coen® to supply option for changing the existing low NOx DAF™ burner to Ultra Low NOx burner. Coen has over 400 ULN burner installations using the RMB™ family of burners to meet single digit NOx. The RMB™ will require 30% FGR to achieve 9 PPM. Coen is offering a budget price including a new FD fan package, the new trains along with Fyr-Monitor™ BMS/CCS PLC based systems to assure the controls match the performance desired for Ultra Low NOx operation.

2.0 Burner Design Basis & Specifications

2.1 Boiler Information

Number of boilers	1
Number of burners per boiler	1
Boiler manufacturer	Foster Wheeler
Boiler designation	AG-5195
Furnace dimensions: Width inside (feet)	7.08'
Height (feet)	13.71'
Length (feet)	36.75'
Length for flame (feet)	31.75'
Steam capacity (lb/hr)	208,562
Design boiler HHV BTU input (mmbtu/hr) NG	253.77
Boiler furnace pressure at proposed conditions ("w.c.)	18.51
Steam pressure (psig)	350
Steam temperature (°F)	SAT
Boiler Feedwater temperature (°F)	236
Boiler efficiency Natural Gas	---
Maximum boiler stack height (feet)	35-40
Location	Indoor
Economizer used	Yes

2.2 Electrical & Utilities

Fan electrical characteristics (v/hz/ph)	480/60/3
Panel electrical characteristics (v/hz/ph)	120/60/1
Instrument air supply (clean, dry, and oil-free)	100 psig

2.3 Codes

Area classification	Non-Hazardous
NEMA class rating	NEMA 4
Code requirements	NFPA 85
Piping requirements	Coen Standard
Insurance requirements	None

2.4 Combustion Air

Combustion air temperature (°F)	80
Air humidity (%)	50
Air density at standard conditions (lbm/ft^3)	0.075
Mix density with FGR/Combustion air (lbm/ft^3)	0.0512
Mix Temperature FGR/combustion air	145
Plant elevation (FASL)	6.250
Combustion air pre-heat	No

2.5 Fuels

Main gas fuel .... NG
Ignition fuel .... Natural Gas

NG Gas Details:
Higher heating value (btu/scf) 1,064
Specific gravity 0.61

2.6 Burner Performance

Burner pressure drop ("w.c.) 10.0
Burner excess air 15
FGR percent 30
Boiler turndown based on steam output: 6:1
NG regulated supply pressure required at train inlet (psig) 40
N.Gas Pilot gas pressure required (psig) 1.0

2.7 Burner Estimated Emissions

Fuel: NG
NOx (ppm, ref 3% O2) 9
CO (ppm, ref 3% O2) 123

Notes:
1. Emission guarantees are from 25-100% MCR for NG.
2. Emission guarantees based on HHV.
3. Coen will guarantee the stack CO emission to be less than 123 PPM provided furnace leakage does not contribute any CO to the total CO emissions. This guarantee is based on; 1) operating with 15% excess air at high fire; 2) 31.75 ft (min) furnace length to the superheater; 3) the boiler meeting the minimum construction requirements for furnace side wall construction and seals at the front wall and drum and 4) the customer providing sampling port for measuring the CO emissions.

2.8 Paint and Finish
Coen surface preparation and painting will be as follows:

Product
- Acrylic Emulsion primer/finish, no topcoat
- Sherwin-Williams DTM Acrylic or equivalent
- SW data sheet 1.21

Surface Preparation
- SSPC-SP6

Dry Film Thickness (S-W, other mfg see product sheet)
- 5.0 - 6.0 mils

Performance
- Consult the manufacturer's product information sheet

Technique
- Consult the manufacturer's application bulletin and JZ 9001-OPS-MFG-58

Inspection
- Consult JZ 9001-OPS-QC-61

3.0 Scope of Supply

3.1 Burner Equipment

The following is included as part of Coen's offering:

Windbox, Damper (Qty: 1)

The windbox houses the burner and is constructed of carbon steel and has insulation to reduce the surface temperature due to the FGR and combustion air mixture. The windbox is to be seal welded to the boiler front plate and is of sufficient size to provide air cooling to a major portion of the boiler front plate.

A jackshaft control drive system is mounted on the windbox front and includes:

- Purge and low fire position switches
- Ball bearing pillow blocks, self aligning, and permanently lubricated
- Mechanical linkage constructed from 1/2" pipe with heavy duty, aircraft type ends to eliminate backlash.
- Jackshaft, 1-3/16 solid round stock

The jackshaft must be driven by an actuator and will be linked to the following components:

- Windbox damper

A combustion air damper is mounted on windbox. The damper is a slow opening, multibladed, streamline design. It is designed to have a relatively straight line characteristic in respect to air flow versus damper positions. The maximum air leakage will not exceed 10% in the closed position.

Jackshaft Actuator (Qty: 1)

The jackshaft actuator is mounted on the windbox and is electrically driven. The actuator with smart positioner accepts a 4-20 mA control input signal and drives all items linked to jackshaft.

FD Fan-FGR Package (Qty: 1)

Coen will be supplying a new FD fan package to deliver the combustion air and Induce 30% FGR to the new RMB Ultra Low NOx burner. The following is included:

- FD Fan package with 800 HP TEFC motor 4160 V/3PH/60HZ, IVC damper with actuator with smart I/P positioner. Note fan will be shipped partial-assembled.
- FGR inlet box with manual damper.
- 38"D FGR x 12"D connection as part of the FGR inlet box.
- Inlet silencer with piezometer with loose DP transmitter & integral manifold valve (field installed).
- FGR damper, 38"D with actuator and I/P positioner and position feedback – shipped loose.
- FGR thermal mass flow meter with 4-20 mA output – shipped loose

RMB Burner (Qty: 1)

The RMB includes the following sub-assemblies:
- One (1) primary (inner) register with integral gas injectors and air flow swirl vanes
- One (1) secondary (outer) register with integral gas injectors and air flow vanes
- One (1) set of pre-cast refractory quarl segments that comprise of the inner zone throat.
- Two (2) manual gas butterfly valves
- Two (2) gas pressure gauges c/w isolation cocks
- One (1) burner front hub assembly, complete with two observation ports and flame scanner swivel mounts
- One (1) burner guide ring for the purpose of centering the burner in the windbox

Natural Gas Pilot (Qty: 1)

The pilot is electrically ignited and is interruptible per NFPA Class III requirements. The pilot electrode is sparked by a 6000 Volt transformer.

Natural Gas Pilot Train (Qty: 1)

Pilot train, fully assembled and mounted and wired to a junction box on the windbox with the following components:

- One inlet manual shutoff valve, bronze body.
- One strainer, 100 mesh, cast iron body.
- One pressure regulating valve, aluminum body.
- Two safety shutoff valves aluminum body.
- Two safety shutoff valve leak test valves.
- One vent valve, aluminum body.
- One manual shutoff valve, bronze body.
- One pressure gage, 4-1/2".
- One flex hose, stainless steel.

Natural Gas Train (Qty: 1)

The main gas train is assembled and mounted on the windbox. Portion (*) of the train will be assembled and shipped loose for field installation, support, wiring, etc. The following components are included:

- *One manual shutoff valve, cast iron body, Homestead.
- *One strainer, cast iron body.
- *One pressure regulating valve, cast iron body, Fisher.
- *One supply pressure gauge, 4-1/2" Ashcroft.
- *One flow meter with 4-20mA output signal
- One low pressure switch, Ashcroft.
- Two safety shutoff valves each with a proof of closure switch, cast iron body, Maxon CC-5000.
- Two safety shutoff valve leak test valves.
- One vent valve, cast iron body, Maxon.
- One vent manual test valve, bronze body.
- One manual shutoff valve, cast iron body.
- One high pressure switch, Ashcroft.
- One Main pneumatic flow control valve, 125# FF cast iron body, with smart I/P positioner, mechanical down stop and low fire switch.
- Two burner pressure gauges, 4-1/2" Ashcroft.

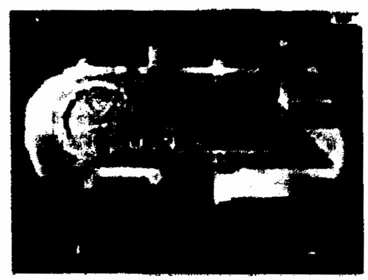
Fyr-Monitor BMS and CCS (Metering) Control Panel (Qty: 1)

Fyr-Monitor touchscreen control system which will have burner management system (BMS) and combustion controls system (CCS) in the same panel and will use same touchscreen. The CCS type is Metering with fully-metered cross limiting, O2 trim, FGR trim, 3-Element Feedwater and Draft controls. Two PLCs will be used, one for BMS and one for CCS. The touchscreen will be a 10.4" CTC color screen and will have the following control screens.

(Rainhood not included)

Main
Opening screen which shows control loops and pertinent BMS information for starting and monitoring burner.

Navigator
Provides access to other screens except system setup screens



Surface Clean Allows screen cleaning without changing control settings

Flow Diagram
Piping style diagram of whole boiler process with numerical readouts of measured process values and showing valves open or closed, etc.

Alarm Status
Displays current alarm conditions in an annunciator style layout.

Alarm History Logs most recent alarm conditions.

Burner Control
Detailed information about all the control loops in the system.

Trending
Trends of all process variables controlled by the Fyr Monitor. Note, data is not stored, just shown for about 30 minutes of operation.

Two Allen Bradley PLCs will be mounted in a panel which will house all the necessary I/O modules, relays, terminals, etc. The following is included:

- (2) Allen Bradley CompactLogix PLC with all required I/O modules
- CTC touchscreen panel with 256 colors and TFT (active matrix) LCD.
    - Size: 10.4"
- Memory: 8 megabyte flash ROM, 8 megabyte RAM
- The above items mounted in Nema 4X enclosure 48" x 36" x 24

Scanner system is as follows:

Coen system consisting of the following equipment:

Scanner Model: (2) Fireye scanners
Note: Scanner(s) require cooling/purge air.

Loose pressure limits included: (Qty: 1 ea)
- One Excess Steam pressure switch
- One High Furnace pressure switch
- One Low Combustion Air flow switch
- One Low Purge Air flow switch
- One Low Instrument Air pressure switch

3.2 Items Not Included In our Proposal- Existing

- Remove, disposal, demolition etc of existing equipment to allow for new equipment.
- Installation of new equipment
- Removal of windbox, DAF burner and throat
- Modification to the boiler front wall (as required) including all material and installation for the new RMB throat.
- Pipe, fittings, ducting, gaskets, wire and conduit as required for installation of valves, dampers and Fyr-Monitor panels
- Boiler drum level probes
- Boiler auxiliary drum level cut-out switch
- New FD fan package foundation
- New FD fan outlet duct including expansion joint to connect FD fan outlet to the
- New windbox damper inlet connection
- New FD Fan inlet supports (as required to support inlet silencer/FGR box).
- New FGR ducting, expansion joint, supports, connectors, etc.
- New FD Fan motor starter or VFD
- Any Pressure safety switches not listed above for BMS interface per NFPA-85
- Reuse Feedwater controls and instruments
- Reuse Draft controls
- O2 analyzer
- Source of ignitor/scanner cooling/purge air
- All insulation and lagging
- Erection
- Start-up Service
- Freight

4.0 Price

Budget: One RMB ULN unit as detailed below will be
SEVEN HUNDRED & FIFTY THOUSHAND DOLLARS .... **$750,000.00**.
The following equipment changes from the Base offering to be included.

Price Validity: Above prices are valid for acceptance by May 1, 2012 for delivery within 30 weeks of receipt of order unless otherwise specified. See Schedule section, below, for estimated lead times.

Prices do not include taxes. Freight cost is not included in our price. Equipment will be shipped Ex-works. point of manufacture, freight collect.

5.0 Payment

Subject to credit approval, progress payments will be required according to the following schedule: Net 30 days

15% of total order upon issuance of the purchase order or contract
30% on drawing transmittal
45% six (6) weeks after drawing transmittal
10% upon notice of availability of shipment

Escalation charges shall be applied to orders whose delivery dates are delayed beyond thirty (30) days from the contractual delivery date due to no fault of Coen and when such delay has caused an increase in the cost of the goods or services to Coen. Escalation charges shall be based upon either: (1) the Producer Price Index as published by the U.S. Department of Labor, Bureau of Labor Statistics for Finished Goods, Capital Equipment only, or (2) the U.S. Department of Labor, Employment Cost Index (ECI), Private Industry, Table 3. Employment Cost Index for total compensation for private industry workers, by industry and occupational group; Manufacturing Industry, as applicable. The base line for calculating the adjustment shall be the date of the contract.

6.0 Drawing and Schedule

Drawings will be submitted eight (8) weeks after receipt of purchase order and all engineering information. Shipment will be fourteen (14) weeks from receipt of approved drawings. Note: Actual dates will be confirmed upon receipt of the purchase order and scheduling meeting completed.

The following drawings/documents will be submitted for approval:

General Arrangement Drawing - Windbox-burner-trains
General Arrangement Drawing - Burner
Flow Diagram
Fyr-Monitor BMS/CCS Enclosure and Wiring Schematic
Fyr-Monitor BMS Sequence of Operation
Fyr-Monitor CCS Controls Narrative
Bill of Materials
IOM manual

7.0 Clarifications and Exceptions to the Specifications

None received. Coen standard scope, design, material and fabrication to be supplied

8.0 Terms & Conditions of Sale

This is a budgetary proposal and is intended only as an estimate to facilitate your planning processes and does not constitute a commitment or offer to sell goods or services at the prices and terms referenced herein. Any firm offer or binding quotation will be the subject of a formal proposal at a future date.

To the extent an order is issued by you and accepted by Coen, then the resulting contract documents shall be subject to the attached Coen Company, Inc. Standard Terms and Conditions of Sale (the "T&Cs") and this proposal (including, without limitation, the T&Cs) shall be incorporated by reference into such contract documents. In the case of a conflict among the contract documents, then the terms of the proposal (including, without limitation, the T&Cs) shall take precedence.

This proposal document is confidential and intended solely for the use of the individual or entity to which it is addressed. If you have received this proposal in error, please contact the sender and destroy all copies of the original message.

Regards,

Wayne A. Wieszczyk
Sr. Application Engineer
Boiler Burner Group
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Appendix C: Criteria Pollutant Emission Inventory

PSD APPLICABILITY SUMMARIES

Emissions Changes: Project Only, No Contemporaneous Sources

	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr	Fluorides ton/yr	GHG ton/yr	CO_2e ton/yr
Baseline Actual Emissions (BAE) for Project	182.8	182.8	182.8	414.2	4431.3	4.2	1441.1	0.023	8.0	1,165,771	1,167,598
New Boiler Emissions (PTE = PAE) >	8.3	8.3	8.3	12.2	67.9	0.7	6.0	0.001	0	130,049	130,264
Debottlenecked Sources (PAE) >	224.7	224.7	224.7	503.3	5955.0	4.4	1873.7	0.028	9.6	1,529,044	1,531,350
Projected Actual Emissions (PAE) for Project	233.0	233.0	233.0	515.5	6022.8	5.0	1879.7	0.029	9.6	1,659,093	1,661,614
Project Emissions Increase	50.2	50.2	50.2	101.4	1591.5	0.8	438.6	0.005	1.6	493,321	494,015
Significant Emission Rate (SER)	25	15	10	40	100	40	40	0.6	3	250	75,000
Is the Project Emissions Increase Significant?	Yes	Yes	Yes	Yes	Yes	No	Yes	No	No	Yes	Yes

Net Emissions Changes: Includes Both Project and Contemporaneous Sources

	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr	Fluorides ton/yr	GHG ton/yr	CO_2e ton/yr
New Boiler Emissions (Project)	8.3	8.3	8.3	12.2	67.9	0.7	6.0	0.001	0	130,049	130,264
Debottlenecked Sources (Project)	41.9	41.9	41.9	89.1	1523.7	0.1	432.6	0.005	1.6	363,273	363,752
Project Subtotal >	50.2	50.2	50.2	101.4	1591.5	0.8	438.6	0.005	1.6	493,321	494,015
New Contemporaneous Sources	22.1	22.1	22.1	37.5	29.3	N/A	9.2	N/A	N/A	--- *	--- *
Existing Contemporaneous Sources, Increases	7.2	7.2	7.2	1.1	0	N/A	0	N/A	N/A	--- *	--- *
Existing Contemporaneous Sources, Decreases	-0.1	-0.1	-0.1	0	0	N/A	0	N/A	N/A	0	0
Contemporaneous Subtotal >	29.2	29.2	29.2	38.6	29.3	N/A	9.2	N/A	N/A	--- *	--- *
Sum of Project and Contemporaneous Emissions	79.4	79.4	79.4	140.0	1620.8	N/A	447.8	N/A	N/A	493,321	494,015
Significant Emission Rate (SER)	25	15	10	40	100	40	40	0.6	3	250	75,000
Trigger PSD?	Yes	Yes	Yes	Yes	Yes	No	Yes	No	No	Yes	Yes

* The increase in GHG emissions from the project (i.e., new boiler and debottlenecked sources) is significant and there are no creditable contemporaneous decreases of GHG. Thus, project clearly triggers PSD for GHG (BACT for the new boiler applies regardless) and no further quantification is performed.

Blue values are input values and black are calculated values

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
AIR SCIENCES INC	PROJECT NO: 170-12-2	PAGE: 2	OF: 5	SHEET: Applicability
ENGINEERING CALCULATIONS	SUBJECT: Emissions Inventory	DATE: July 2, 2012		

SUMMARY OF BASELINE ACTUAL EMISSIONS (PROJECT SOURCES)

WDEQ Source ID	Source Description	Source Type	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr	GHG ton/yr	CO_2e ton/yr
---	New Package Boiler	New	0	0	0	0	0	0	0	0	0	0
02A	Ore Crusher Building #1	Debottlenecked	7.0	7.0	7.0	0	0	0	0	0	0	0
06A	Product Silos - Top #1	Debottlenecked	1.3	1.3	1.3	0	0	0	0	0	0	0
06B	Product Silos - Bottom #1	Debottlenecked	0.0	0.0	0.0	0	0	0	0	0	0	0
07	Product Loadout Station	Debottlenecked	2.2	2.2	2.2	0	0	0	0	0	0	0
15	DR-1 & 2 Steam Tube Dryers	Debottlenecked	8.6	8.6	8.6	0	0	0	0	0	117,265	117,265
16	Dryer Area	Debottlenecked	3.7	3.7	3.7	0	0	0	0	0	0	0
17	"A" and "B" Calciners	Debottlenecked	61.4	61.4	61.4	268.5	1252.6	4.2	1236.1	0.0225	372,352	373,965
46	Ore Transfer Station	Debottlenecked	3.1	3.1	3.1	0	0	0	0	0	0	0
48	"C" Calciner	Debottlenecked	10.3	10.3	10.3	5.1	528.7	0	71.4	0.0001	76,128	76,157
50	"C" Train Dryer Area	Debottlenecked	2.9	2.9	2.9	0	0	0	0	0	0	0
51	Product Dryer #5	Debottlenecked	3.7	3.7	3.7	35.7	178.7	0	1.1	0.0002	153,323	153,363
52	Product Silo - Top #2	Debottlenecked	2.1	2.1	2.1	0	0	0	0	0	0	0
53	Product Silo - Bottom #2	Debottlenecked	0.8	0.8	0.8	0	0	0	0	0	0	0
76	"D" Train Primary Ore Screening	Debottlenecked	10.4	10.4	10.4	0	0	0	0	0	0	0
79	Ore Transfer Point	Debottlenecked	3.6	3.6	3.6	0	0	0	0	0	0	0
80	"D" Ore Calciner	Debottlenecked	32.0	32.0	32.0	46.6	2444.1	0	131.4	0.0004	275,796	275,899
81	"D" Train Dryer Area	Debottlenecked	2.1	2.1	2.1	0	0	0	0	0	0	0
82	DR-6 Product Dryer	Debottlenecked	10.6	10.6	10.6	58.2	27.2	0	1.1	0.0002	170,906	170,949
99	Crusher Baghouse #2	Debottlenecked	14.0	14.0	14.0	0	0	0	0	0	0	0
100	Calciner Coal Bunker	Debottlenecked	0.2	0.2	0.2	0	0	0	0	0	0	0
103	East Ore Reclaim	Debottlenecked	1.4	1.4	1.4	0	0	0	0	0	0	0
104	West Ore Reclaim	Debottlenecked	1.2	1.2	1.2	0	0	0	0	0	0	0
		Total >	182.8	182.8	182.8	414.2	4431.3	4.2	1441.1	0.023	1,165,771	1,167,598

SUMMARY OF BASELINE ACTUAL EMISSIONS (CONTEMPORANEOUS SOURCES)

WDEQ Source ID	Source Description	Source Type	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr
33	Sulfur Burner	Existing	0	0	0	0 2	0	N/A	0	N/A
35	Sulfite Dryer	Existing	3 24	3 24	3 24	3 24	0	N/A	0	N/A
36	Sulfite Product Bin #1	Existing	0 13	0 13	0 13	0 13	0	N/A	0	N/A
37	Sulfite Product Bin #2	Existing	0 13	0 13	0 13	0 13	0	N/A	0	N/A
38	Sulfite Product Bin #3	Existing	0 13	0 13	0 13	0 13	0	N/A	0	N/A
64	Sulfite Blending #2	Existing	0 01	0 01	0 01	0 01	0	N/A	0	N/A
65	Sulfite Blending #1	Existing	0 02	0 02	0 02	0 02	0	N/A	0	N/A
70	Sodium Sulfite Bagging Silo	Existing	0 06	0 06	0 06	0 06	0	N/A	0	N/A
90	Blending Bag Dump #1	Existing	0 02	0 02	0 02	0 02	0	N/A	0	N/A
91	Blending Bag Dump #2	Existing	0	0	0	0	0	N/A	0	N/A
94	Sulfite Loadout	Existing	0 08	0 08	0 08	0 08	0	N/A	0	N/A
105	S-300 Dryer #1	New	0	0	0	0	0	N/A	0	N/A
106	S-300 Silo and Rail Loadout #1	New	0	0	0	0	0	N/A	0	N/A
107	S-300 Dryer #2	New	0	0	0	0	0	N/A	0	N/A
108	S-300 Silo and Rail Loadout #2	New	0	0	0	0	0	N/A	0	N/A
88b	Trona Products Transloading #3	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Excavation	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Stockpiling	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Haul Road Activity	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Melt Tank	New	0	0	0	0	0	N/A	0	N/A
E3	Waukesha F18GSI (GVBH compressor)	New	0	0	0	0	0	N/A	0	N/A
E4	GM 8 1L (GVBH Pump)	New	0	0	0	0	0	N/A	0	N/A
E5	GM 4 3L (GVBH Pump)	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Stamler System	New	0	0	0	0	0	N/A	0	N/A
GVBH Fl	GVB Flare	New	0	0	0	0	0	N/A	0	N/A
EG-3	Caterpillar 3456 (Emergency Shaft Generator)	New	0	0	0	0	0	N/A	0	N/A
EG-4a	Volvo TAD1353 GE (Main Shaft Emer Gen)	New	0	0	0	0	0	N/A	0	N/A
EG-4b	Volvo TAD1353 GE (Main Shaft Emer Gen)	New	0	0	0	0	0	N/A	0	N/A
EG-4c	Volvo TAD1353 GE (Main Shaft Emer Gen)	New	0	0	0	0	0	N/A	0	N/A
N/A	TEG Dehydration Unit	New	0	0	0	0	0	N/A	0	N/A
N/A	Two (2) Reboilers Heaters	New	0	0	0	0	0	N/A	0	N/A
N/A	Katolight SENL80FGC4	New	0	0	0	0	0	N/A	0	N/A
		Total >	3 8	3 8	3.8	4 0	0	N/A	0	N/A

N/A = Emissions from project sources (new boiler and debottlenecked sources) are not significant so contemporaneous netting analysis is not necessary

SUMMARY OF PROJECTED ACTUAL EMISSIONS (PROJECT SOURCES)

WDEQ Source ID	Source Description	Source Type	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr	GHG ton/yr	CO_2e ton/yr
---	New Package Boiler	New	8.3	8.3	8.3	12.2	67.9	0.7	6.0	0.001	130,049	130,264
02A	Ore Crusher Building #1	Debottlenecked	7.0	7.0	7.0	0	0	0	0	0	0	0
06A	Product Silos - Top #1	Debottlenecked	1.3	1.3	1.3	0	0	0	0	0	0	0
06B	Product Silos - Bottom #1	Debottlenecked	2.2	2.2	2.2	0	0	0	0	0	0	0
07	Product Loadout Station	Debottlenecked	5.3	5.3	5.3	0	0	0	0	0	0	0
15	DR-1 & 2 Steam Tube Dryers	Debottlenecked	9.2	9.2	9.2	0	0	0	0	0	152,304	152,304
16	Dryer Area	Debottlenecked	3.9	3.9	3.9	0	0	0	0	0	0	0
17	"A" and "B" Calciners	Debottlenecked	71.8	71.8	71.8	321.2	1554.9	4.4	1498.1	0.0269	470,255	472,272
46	Ore Transfer Station	Debottlenecked	3.1	3.1	3.1	0	0	0	0	0	0	0
48	"C" Calciner	Debottlenecked	21.5	21.5	21.5	12.0	1238.0	0	197.1	0.0003	184,152	184,218
50	"C" Train Dryer Area	Debottlenecked	3.1	3.1	3.1	0	0	0	0	0	0	0
51	Product Dryer #5	Debottlenecked	4.4	4.4	4.4	41.3	206.7	0	1.3	0.0002	177,020	177,066
52	Product Silo - Top #2	Debottlenecked	2.2	2.2	2.2	0	0	0	0	0	0	0
53	Product Silo - Bottom #2	Debottlenecked	2.0	2.0	2.0	0	0	0	0	0	0	0
76	"D" Train Primary Ore Screening	Debottlenecked	10.7	10.7	10.7	0	0	0	0	0	0	0
79	Ore Transfer Point	Debottlenecked	3.7	3.7	3.7	0	0	0	0	0	0	0
80	"D" Ore Calciner	Debottlenecked	41.3	41.3	41.3	55.7	2921.3	0	176.0	0.0005	330,014	330,138
81	"D" Train Dryer Area	Debottlenecked	2.2	2.2	2.2	0	0	0	0	0	0	0
82	DR-6 Product Dryer	Debottlenecked	12.4	12.4	12.4	73.0	34.1	0	1.3	0.0002	215,298	215,352
99	Crusher Baghouse #2	Debottlenecked	14.0	14.0	14.0	0	0	0	0	0	0	0
100	Calciner Coal Bunker	Debottlenecked	0.9	0.9	0.9	0	0	0	0	0	0	0
103	East Ore Reclaim	Debottlenecked	1.4	1.4	1.4	0	0	0	0	0	0	0
104	West Ore Reclaim	Debottlenecked	1.2	1.2	1.2	0	0	0	0	0	0	0
		Total >	233.0	233.0	233.0	515.5	6022.8	5.0	1879.7	0.0287	1,659,093	1,661,614

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
AIR SCIENCES INC	PROJECT NO: 170-12-2	PAGE: 5	OF: 5	SHEET: Applicability
ENGINEERING CALCULATIONS	SUBJECT: Emissions Inventory	DATE: July 2, 2012		

SUMMARY OF PROJECTED ACTUAL EMISSIONS (CONTEMPORANEOUS SOURCES)

WDEQ Source ID	Source Description	Source Type	PM ton/yr	PM_{10} ton/yr	$PM_{2.5}$ ton/yr	NO_X ton/yr	CO ton/yr	SO_2 ton/yr	VOC ton/yr	Lead ton/yr
33	Sulfur Burner	Existing	0	0	0	1 3	0	N/A	0	N/A
35	Sulfite Dryer	Existing	6 13	6 13	6 13	0	0	N/A	0	N/A
36	Sulfite Product Bin #1	Existing	0 44	0 44	0 44	0	0	N/A	0	N/A
37	Sulfite Product Bin #2	Existing	0 44	0 44	0 44	0	0	N/A	0	N/A
38	Sulfite Product Bin #3	Existing	0 44	0 44	0 44	0	0	N/A	0	N/A
64	Sulfite Blending #2	Existing	0 35	0 35	0 35	0	0	N/A	0	N/A
65	Sulfite Blending #1	Existing	0 31	0 31	0 31	0	0	N/A	0	N/A
70	Sodium Sulfite Bagging Silo	Existing	1 18	1 18	1 18	0	0	N/A	0	N/A
90	Blending Bag Dump #1	Existing	0 22	0 22	0 22	0	0	N/A	0	N/A
91	Blending Bag Dump #2	Existing	0 22	0 22	0 22	0	0	N/A	0	N/A
94	Sulfite Loadout	Existing	1 31	1 31	1 31	0	0	N/A	0	N/A
105	S-300 Dryer #1	New	5 6	5 6	5 6	0	0	N/A	0	N/A
106	S-300 Silo and Rail Loadout #1	New	0 3	0 3	0 3	0	0	N/A	0	N/A
107	S-300 Dryer #2	New	5 6	5 6	5 6	0	0	N/A	0	N/A
108	S-300 Silo and Rail Loadout #2	New	0 3	0 3	0 3	0	0	N/A	0	N/A
88b	Trona Products Transloading #3	New	0 9	0 9	0 9	0	0	N/A	0	N/A
N/A	DECA Excavation	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Stockpiling	New	0	0	0	0	0	N/A	0	N/A
N/A	DECA Haul Road Activity	New	8 9	8 9	8 9	0	0	N/A	0	N/A
N/A	DECA Melt Tank	New	0	0	0	0	0	N/A	0	N/A
E3	Waukesha F18GSI (GVBH compressor)	New	0	0	0	2 7	3 9	N/A	1 9	N/A
E4	GM 8 1L (GVBH Pump)	New	0	0	0	1 4	2 0	N/A	1	N/A
E5	GM 4 3L (GVBH Pump)	New	0	0	0	0 8	1 2	N/A	0 6	N/A
N/A	DECA Stamler System	New	0	0	0	0	0	N/A	0	N/A
GVBH Fl	GVB Flare	New	0	0	0	25 7	15 0	N/A	3 6	N/A
EG-3	Caterpillar 3456 (Emergency Shaft Generator)	New	0 2	0 2	0 2	2 6	3 2	N/A	0 4	N/A
EG-4a	Volvo TAD1353 GE (Main Shaft Emer Gen)	New	0 1	0 1	0 1	1 0	0 9	N/A	0 1	N/A
EG-4b	Volvo TAD1353 GE (Main Shaft Emer Gen)	New	0 1	0 1	0 1	1 0	0 9	N/A	0 1	N/A
EG-4c	Volvo TAD1353 GE (Main Shaft Emer Gen)	New	0 1	0 1	0 1	1 0	0 9	N/A	0 1	N/A
N/A	TEG Dehydration Unit	New	0	0	0	0	0	N/A	0 6	N/A
N/A	Two (2) Reboilers Heaters	New	0	0	0	0 1	0 1	N/A	0	N/A
N/A	Katolight SENL80FGC4	New	0	0	0	1.2	1 2	N/A	0.8	N/A
		Total >	33.1	33.1	33 1	38 8	29 3	N/A	9.2	N/A

N/A = Emissions from project sources (new boiler and debottlenecked sources) are not significant so contemporaneous netting analysis is not necessary

Appendix D: Estimation of Annual GHG Emissions from Gas-Fueled Boiler

	Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
AIR SCIENCES INC		PROJECT NO: 170-12-2	PAGE: 1	OF: 3	SHEET: GHG Sources
	ENGINEERING CALCULATIONS	SUBJECT: Emissions Inventory	DATE: June 12, 2012		

ACTUAL ANNUAL OPERATING HOURS AND THROUGHPUTS - SOLVAY ANNUAL REPORTS TO WDEQ

WDEQ Source ID	Source Description	Annual Operating Hours (hr/yr) 2006	2007	2008	2009	2010	Throughput (ton/yr) * 2006	2007	2008	2009	2010
15	DR-1 & 2 Steam Tube Dryers	8,364	8,408	8,159	8,131	8,392	967,105	944,140	755,359	786,186	771,037
17	"A" and "B" Calciners	8,507	8,627	8,344	8,673	8,276	1,202,621	1,592,932	1,566,774	1,773,989	1,439,276
48	"C" Calciner	7,580	4,813	3,739	4,420	3,853	1,046,548	540,553	422,508	443,485	476,594
51	Product Dryer #5	8,027	8,361	8,473	8,029	8,432	722,311	819,929	805,135	729,938	812,220
80	"D" Ore Calciner	7,671	7,655	8,133	6,254	8,099	1,516,472	1,677,003	1,792,095	1,300,723	1,814,177
82	DR-6 Product Dryer	8,689	8,466	8,400	8,098	8,539	789,384	819,496	1,008,988	884,317	964,228

* Conservatively assume that throughput is 100% trona ore for the calciners (#17, #48, #80) and 100% soda ash product for the dryers (#15, #51, #82).

ACTUAL ANNUAL OPERATING FUEL CONSUMPTION - SOLVAY ANNUAL REPORTS TO WDEQ

WDEQ Source ID	Source Description	Fuel	Coal Consumption (tons/year) 2006	2007	2008	2009	2010	Coal Usage (MMBtu/yr) * 2006	2007	2008	2009	2010
17	"A" and "B" Calciners	Coal	47,086	102,883	101,966	112,190	101,167	941,720	2,057,660	2,039,320	2,243,800	2,023,340

* Assuming coal thermal equivalent of 10,000 Btu/lb.

WDEQ Source ID	Source Description	Fuel	Gas Consumption (MMscf/year) 2006	2007	2008	2009	2010	Gas Usage (MMBtu/year) * 2006	2007	2008	2009	2010
17	"A" and "B" Calciners	Gas	507	---	---	---	---	517,140	---	---	---	---
48	"C" Calciner	Gas	1,004	555	432	484	463	1,024,080	566,100	440,640	493,680	472,260
51	Product Dryer #5	Gas	609	678	704	649	697	621,180	691,560	718,080	661,980	710,940
80	"D" Ore Calciner	Gas	1,465	1,709	1,899	1,347	1,788	1,494,300	1,743,180	1,936,980	1,373,940	1,823,760
82	DR-6 Product Dryer	Gas	678	672	829	727	778	691,560	685,440	845,580	741,540	793,560

* Assuming natural gas thermal equivalent of 1,020 Btu/scf.

NEW BOILER PARAMETERS

WDEQ Source ID	Source Description	Fuel(s)	Annual Hours	Thermal Rating (MMBtu/hr)	Max. Gas Usage (MMBtu/yr) *	Valves	Connectors (flanges)
—	New Package Boiler	Gas	8760	254	2,225,040	6	18

* Assuming natural gas thermal equivalent of 1,020 Btu/scf.

EMISSION FACTORS

Pollutant	Combustion ** EF (kg/MMBtu) Gas	Coal *	Combustion ** EF (lb/MMBtu) Gas	Coal *	Process *** EF Trona Ore (ton CO_2/ton)	Process *** EF Soda Ash Produced (ton CO_2/ton)	Fugitives **** Valve (scf/hr/component)	Connector	GWP Multiplier
CO_2	53.02	97.02	116.9	213.9	0.097	0.138	---	---	1
CH_4	0.001	0.011	0.002	0.02	---	---	2.903	0.396	21
N_2O	0.0001	0.0016	0.0002	0.004	---	---	---	---	310

* For subbituminous coal

** From 40 CFR 98, Subpart C, Tables C-1 and C-2.

*** Per 40 CFR 98.293 (40 CFR 98, Subpart CC - Soda Ash Manufacturing), Eq. CC-1 for trona ore (applicable to calciners) and Eq. CC-2 for soda ash produced (applicable to dryers).

**** Per 40 CFR 98, Subpart W, Table W-1A (Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production) Western U.S., Population Emission Factors - All Components, Gas Service; assume all gas emitted as methane to be conservative.

Assumptions			Reference
Coal thermal equivalent	10,000	Btu/lb	Solvay
Natural gas thermal equivalent	1,020	Btu/scf	AP-42, Section 1.4 (Revision 7/98)
Density of Natural Gas	0.042	lb/scf	AP-42, Section 1.4 (Revision 7/98)

Blue are input values and black are calculated values

Conversions	
453.59	g/lb
2000	lb/ton
2.20462	lb/kg

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
AIR SCIENCES INC	PROJECT NO: 170-12-2	PAGE: 2	OF: 3	SHEET: GHG Sources
ENGINEERING CALCULATIONS	SUBJECT: Emissions Inventory	DATE: June 12, 2012		

PROJECTED GHG MASS EMISSION INCREASES FROM NEW BOILER AND DEBOTTLENECKED SOURCES

Assumptions

1) There are no short-term increases in PTE for all sources
2) No existing debottlenecked sources will be physically modified
3) The average production over the past five years is: 2,549,717 tons/year (based on avg. throughput for AQD #7 from 2006 to 2010)
4) Debottleneck results in production increase of: 360,000 tons/year
5) Assume projected annual emissions of existing debottlenecked sources are a function of the production increase (%): 14.1%

GHG Mass Emissions

WDEQ Source ID	Source Description	Actual Annual GHG Mass Emissions (tons/yr) 2006	2007	2008	2009	2010	2007-2008 BAE (tons/yr)	PAE (tons/yr)	Increase (PAE-BAE) (tons/year)
Process Emissions									
---	New Package Boiler	0	0	0	0	0	0	0	0
15	DR-1 & 2 Steam Tube Dryers	133,460	130,291	104,240	108,494	106,403	117,265	152,304	35,039
17*	"A" and "B" Calciners	116,654	154,514	151,977	172,077	139,610	153,246	196,373	43,127
48*	"C" Calciner	101,515	52,434	40,983	43,018	46,230	46,708	115,848	69,140
51*	Product Dryer #5	99,679	113,150	111,109	100,731	112,086	112,129	129,126	16,997
80*	"D" Ore Calciner	147,098	162,669	173,833	126,170	175,975	168,251	200,821	32,570
82*	DR-6 Product Dryer	108,935	113,090	139,240	122,036	133,063	126,165	158,900	32,735
Combustion Emissions									
---	New Package Boiler	0	0	0	0	0	0	130,044	130,044
15**	DR-1 & 2 Steam Tube Dryers	0	0	0	0	0	0	0	0
17*	"A" and "B" Calciners	130,951	220,087	218,126	239,997	216,416	219,107	273,883	54,776
48*	"C" Calciner	59,853	33,086	25,754	28,853	27,602	29,420	68,304	38,884
51*	Product Dryer #5	36,305	40,419	41,969	38,690	41,551	41,194	47,894	6,701
80*	"D" Ore Calciner	87,335	101,881	113,208	80,301	106,591	107,545	129,192	21,647
82*	DR-6 Product Dryer	40,419	40,061	49,421	43,340	46,380	44,741	56,398	11,658
Fugitive Emissions ***									
---	New Package Boiler	---	---	---	---	---	0	5	5
	Subtotals >	---	---	---	---	---	1,165,771	1,659,093	493,321

* For the existing sources (#15, #17, #48, #51, #80, #82), multiply the highest annual emissions from 2006 to 2010 by the production increase of 14.1% to determine the projected actual emissions

** Source #15 fed by heat from boiler only, old preheaters on Source #15 are no longer used so there are no actual gaseous combustion emissions

*** Fugitive emissions of natural gas for new valves and connectors (flanges) associated with the new boiler.

GHG Mass Emissions by Constituent

WDEQ Source ID	Source Description	CO_2 (tons/yr) BAE	PAE	Increase	CH_4 (tons/yr) BAE	PAE	Increase	N_2O (tons/yr) BAE	PAE	Increase
Process Emissions										
---	New Package Boiler	0	0	0	0	0	0	0	0	0
15	DR-1 & 2 Steam Tube Dryers	117,265	152,304	35,039	0	0	0	0	0	0
17	"A" and "B" Calciners	153,246	196,373	43,127	0	0	0	0	0	0
48	"C" Calciner	46,708	115,848	69,140	0	0	0	0	0	0
51	Product Dryer #5	112,129	129,126	16,997	0	0	0	0	0	0
80	"D" Ore Calciner	168,251	200,821	32,570	0	0	0	0	0	0
82	DR-6 Product Dryer	126,165	158,900	32,735	0	0	0	0	0	0
Combustion Emissions										
---	New Package Boiler	0	130,041	130,041	0	2	2	0	0.2	0
15	DR-1 & 2 Steam Tube Dryers	0	0	0	0	0	0	0	0	0
17	"A" and "B" Calciners	219,078	273,847	54,769	25	31	6	4	5	1
48	"C" Calciner	29,419	68,302	38,883	1	1	1	0.1	0.1	0
51	Product Dryer #5	41,193	47,893	6,700	1	1	0.1	0.1	0.1	0
80	"D" Ore Calciner	107,543	129,190	21,647	2	2	0.4	0.2	0.2	0
82	DR-6 Product Dryer	44,740	56,397	11,657	1	1	0.2	0.1	0.1	0
Fugitive Emissions										
---	New Package Boiler	0	0	0	0	5	5	0	0	0

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
AIR SCIENCES INC	PROJECT NO: 170-12-2	PAGE: 3	OF: 3	SHEET: GHG Sources
ENGINEERING CALCULATIONS	SUBJECT: Emissions Inventory	DATE: June 12, 2012		

PROJECTED GHG EMISSIONS INCREASES (CO_2e) FROM NEW BOILER AND DEBOTTLENECKED SOURCES

CO_2e Emissions

WDEQ Source ID	Source Description	Actual Annual CO_2e Emissions (tons/yr) 2006	2007	2008	2009	2010	2007-2008 BAE (tons/yr)	PAE (tons/yr)	Increase (PAE-BAE) (tons/year)
Process Emissions									
---	New Package Boiler	0	0	0	0	0	0	0	0
15	DR-1 & 2 Steam Tube Dryers	133,460	130,291	104,240	108,494	106,403	117,265	152,304	35,039
17*	"A" and "B" Calciners	116,654	154,514	151,977	172,077	139,610	153,246	196,373	43,127
48*	"C" Calciner	101,515	52,434	40,983	43,018	46,230	46,708	115,848	69,140
51*	Product Dryer #5	99,679	113,150	111,109	100,731	112,086	112,129	129,126	16,997
80*	"D" Ore Calciner	147,098	162,669	173,833	126,170	175,975	168,251	200,821	32,570
82*	DR-6 Product Dryer	108,935	113,090	139,240	122,036	133,063	126,165	158,900	32,735
Combustion Emissions									
---	New Package Boiler	0	0	0	0	0	0	130,169	130,169
15**	DR-1 & 2 Steam Tube Dryers	0	0	0	0	0	0	0	0
17*	"A" and "B" Calciners	131,722	221,708	219,732	241,764	218,010	220,720	275,899	55,179
48*	"C" Calciner	59,911	33,118	25,778	28,881	27,628	29,448	68,369	38,921
51*	Product Dryer #5	36,340	40,458	42,009	38,727	41,591	41,233	47,940	6,707
80*	"D" Ore Calciner	87,419	101,979	113,317	80,378	106,693	107,648	129,316	21,668
82*	DR-6 Product Dryer	40,458	40,099	49,468	43,381	46,425	44,784	56,452	11,669
Fugitive Emissions									
---	New Package Boiler	0	0	0	0	0	0	95	95
	Subtotals >	---	---	---	---	---	1,167,598	1,661,614	494,015

* For the existing sources (#15, #17, #48, #51, #80, #82), multiply the highest annual emissions from 2006 to 2010 by the production increase of 14.1% to determine the projected actual emissions

** Source #15 fed by heat from boiler only, old preheaters on Source #15 are no longer used so there are no actual gaseous combustion emissions

<u>CO_2 equivalence (CO_2e) is calculated as follows</u>

CO_2e (ton/year) = (CO_2 ton/year x 1)+(CH_4 ton/year x 21)+(N_2O ton/year x 310)

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
AIR SCIENCES INC	PROJECT NO: 170-12-2	PAGE: 1	OF: 1	SHEET: GHG Limit
ENGINEERING CALCULATIONS	SUBJECT: Emissions Inventory	DATE: July 17, 2012		

Package Boiler Information

Boiler Size	254	MMBtu/hour
Hours of operation	8760	hr/year
Natural gas thermal equivalent	1020	Btu/scf

EMISSION FACTORS

General Natural Gas Factors (Weighted U.S. Average) [1]

	CO_2		CH_4		N_2O	
Pollutant	**(kg/MMBtu)**	**(lb/MMBtu)**	**(kg/MMBtu)**	**(lb/MMBtu)**	**(kg/MMBtu)**	**(lb/MMBtu)**
Natural Gas	53.02	116.9	0.001	0.0022	0.0001	0.00022

[1] From 40 CFR 98, Subpart C, Tables C-1 and C-2 (Natural Gas)

Solvay Gas Constituent Data and Associated CO_2 Emission Factors

Constituent	Composition % Volume	Molecular Weight	Composition % Mass	CO_2 EF [1] (kg/MMBtu)	CO_2 EF [1] (lb/MMBtu)
Carbon Dioxide	2.47%	44.01	6.0%	---	---
Nitrogen	0.61%	14.01	0.5%	0	0
Methane	90.45%	16.043	79.8%	52.26	115.2
Ethane	4.07%	30.07	6.7%	62.64	138.1
Propane	1.39%	44.09	3.4%	61.46	135.5
Iso Butane	0.24%	58.1	0.8%	64.91	143.1
Normal Butane	0.27%	58.1	0.9%	65.15	143.6
Iso Pentane [2]	0.13%	72.15	0.5%	70.02	154.4
Normal Pentane [2]	0.10%	72.15	0.4%	70.02	154.4
Hexane	0.24%	86.17	1.1%	67.72	149.3
Helium	0.03%	4.02	0.01%	0	0
	Average >	18.19			

[1] From 40 CFR 98, Subpart C, Table C-1, methane and hexane not available from 40 CFR 98 - values calculated
Derivation of calculated values for methane and hexane are based on mass CO_2 emitted/mass fuel combusted
and HHV for each fuel constituent.
Using methane as an example:
The combustion reaction for methane is: $CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$, so one mole of methane combusted results in one mole of CO_2 formed
Molecular weight of CH_4 = 16.043 g/mol, CO_2 = 44.01 g/mol, so 2.74325 is the ratio of mass CO_2 per unit mass of fuel combusted.
HHV of the combustion of CH_4 is 23,811 Btu/lb.
The ratio of mass CO_2 per unit mass of fuel combusted divided by the HHV and converted to the appropriate units results in the CO_2 EF.
Example, (2.74325 lb CO_2/lb CH_4) x (1/23,811 Btu/lb) x (1 kg/2.20462 lb) x (1,000,000 Btu/MMBtu) = 52.2 kg CO_2/MMBtu = 115.2 lb CO_2/MMBtu
Thus, the EFs for each constituent is based on mass and HHV.
[2] As Pentanes Plus

Weighted CO_2 Emission Factor Calculations

Constituent	Solvay Gas Composition % Mass	Weighted CO_2 EF * (lb/MMBtu)
Weighted CO_2 EF (no slip) [1]	94.0%	118.3
Weighted CO_2 EF (w/ slip) [2]	100.0%	125.3

[1] The weighted CO_2 EF based on the Composition Mass % multiply by the CO_2 EF (mass based with HHV incorporated) for each constituent divided by the total mass % without CO_2 slip included.
[2] Weighted CO_2 EF with 6% CO_2 slip applied.

GWP Multipliers

Fuel Type	GWP Multiplier
CO_2	1
CH_4	21
N_2O	310

PROPOSED GHG BACT LIMITS

Limit Based on Solvay Max. Heat Value Fuel

125.3	lb CO_2/MMBtu
0.0022	lb CH_4/MMBtu
0.00022	lb N_2O/MMBtu
125.3	lb CO_2e/MMBtu

Assumptions

1 mole methane (CH_4) combusts to form 1 mole CO_2		
1 mole hexane (C_6H_{14}) combusts to form 6 moles CO_2		
Molecular weight, CO_2	44.01	g/mol
Molecular weight, CH_4	16.043	g/mol
Molecular weight, C_6H_{14}	86.17	g/mol
HHV, CH_4	23,811	Btu/lb *
HHV, C_6H_{14}	20,526	Btu/lb *

* From: http://www.engineeringtoolbox.com/heating-values-fuel-gases-d_823.html

Conversions

453.59	g/lb
2000	lb/ton
3600	sec/hr
1,000,000	Btu/MMBtu
2.20462	lb/kg

Appendix E: Incremental Costs for Added Boiler Insulation

AIR SCIENCES INC	Air Sciences Inc. ENGINEERING CALCULATIONS	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
		PROJECT NO: 170-12-2	PAGE: 1	OF: 4	SHEET:
		SUBJECT: GHG Insulation Costs	DATE: July 31, 2012		

INCREMENTAL COST CALCULATIONS FOR BOILER INSULATION: 3" INSULATION VS. 4" INSULATION

Assumptions	Units	Reference
Natural gas thermal equivalent	1,020 Btu/scf	AP-42, Section 1.4 (Revision 7/98)
Area of Insulation	2,530 ft^2	Solvay
Boiler Heat Loss	301,800 BTU/ft^2/yr	Solvay - 3" thick insulation
	231,400 BTU/ft^2/yr	Solvay - 4" thick insulation
Cost of Natural Gas	2.34 \$/thousand ft^3	Solvay - current hub price
	0.00234 \$/ ft^3	
	435,897 Btu/\$	
	0.4359 MMBtu/\$	
Cost of Insulation	\$19.00 \$/ ft^2	Solvay - cost of 3" thick insulation*
	\$20.20 \$/ ft^2	Solvay - cost of 4" thick insulation*
Cost of Insulating Boiler	\$48,070	Solvay - cost of 3" thick insulation*
	\$51,106	Solvay - cost of 4" thick insulation*
	\$3,036 one time cost	Difference (4" vs. 3")
	\$151.80 \$/yr ;annualized cost over assumed 20-year life of boiler**	

* Insulation material will be 8# mineral wool with aluminum jacket.
** boiler expected life: e-mail from Davidson, Foster Wheeler, August 3, 2012

CALCULATIONS

Parameter	Units
Heat Loss	
3" Insulation	763.6 MMBtu/yr
4" Insulation	585.4 MMBtu/yr
Reduction in Heat Loss (4" vs. 3")	178.1 MMBtu/yr
Cost of Lost Heat (in terms of Natural Gas)	
3" Insulation	\$1,752 \$/yr
4" Insulation	\$1,343 \$/yr
Incremental Cost Savings (4" vs. 3")	\$409 \$/yr
Combined annualized insulation cost and fuel savings	-\$257 \$/yr
GHG Emissions Reduction (4" vs. 3")	10.41 GHG Mass (tpy)
	10.42 CO_2e (tpy)
Incremental Cost to Insulate to 4"	\$15 \$/ton GHG Mass
(fuel savings not considered)	\$15 \$/ton GHG CO2e
Incremental Cost to Insulate to 4"	-\$25 \$/ton GHG Mass
(with fuel savings considered)	-\$25 \$/ton GHG CO2e
Years to Pay Back *	7.4 years

* Calculated as the ratio of the cost of insulating the boiler (difference 4" vs. 3" insulation) and the incremental cost savings in fuel savings when using 4" vs. 3" insulation.

GHG EMISSION FACTORS

Pollutant	Gas Emission Factor * (kg/MMBtu)	(lb/MMBtu)	GWP Multiplier **
CO_2	53.02	116.9	1
CH_4	0.001	0.002	21
N_2O	0.0001	0.0002	310

* From 40 CFR 98, Subpart C, Tables C-1 and C-2.
** From 40 CFR 98, Subpart A, Appendix, Table A-1.

Conversions	
2000	lb/ton
2.20462	lb/kg

Blue are input values and black are calculated values.

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
AIR SCIENCES INC	PROJECT NO: 170-12-2	PAGE: 2	OF: 4	SHEET:
ENGINEERING CALCULATIONS	SUBJECT: GHG Insulation Costs	DATE: July 31, 2012		

INCREMENTAL COST CALCULATIONS FOR BOILER INSULATION: 4" INSULATION VS. 5" INSULATION

Assumptions	Units	Reference
Natural gas thermal equivalent	1,020 Btu/scf	AP-42, Section 1.4 (Revision 7/98)
Area of Insulation	2,530 ft^2	Solvay
Boiler Heat Loss	231,400 BTU/ft^2/yr	Solvay - 4" thick insulation
	187,700 BTU/ft^2/yr	Solvay - 5" thick insulation
Cost of Natural Gas	2.34 $/thousand ft^3	Solvay - current hub price
	0.00234 $/ ft^3	
	435,897 Btu/$	
	0.4359 MMBtu/$	
Cost of Insulation	$20.20 $/ ft^2	Solvay - cost of 4" thick insulation*
	$24.15 $/ ft^2	Solvay - cost of 5" thick insulation*
Cost of Insulating Boiler	$51,106	Solvay - cost of 4" thick insulation*
	$61,100	Solvay - cost of 5" thick insulation*
	$9,994 one time cost	Difference (5" vs. 4")
	$400 $/yr ;annualized cost over assumed 20-year life of boiler**	

* Insulation material will be 8# mineral wool with aluminum jacket.

CALCULATIONS

Parameter	Units
Heat Loss	
4" Insulation	585.4 MMBtu/yr
5" Insulation	474.9 MMBtu/yr
Reduction in Heat Loss (5" vs. 4")	110.6 MMBtu/yr
Cost of Lost Heat (in terms of Natural Gas)	
4" Insulation	$1,343 $/yr
5" Insulation	$1,089 $/yr
Incremental Cost Savings (5" vs. 4")	$254 $/yr
Combined annualized insulation cost and fuel savings	$146 $/yr
GHG Emissions Reduction (5" vs 4")	6.46 GHG Mass (tpy)
	6.47 CO_2e (tpy)
Incremental Cost to Insulate to 5"	$62 $/ton GHG Mass
(fuel savings not considered)	$62 $/ton GHG CO2e
Incremental Cost to Insulate to 5"	$23 $/ton GHG Mass
(with fuel savings considered)	$23 $/ton GHG CO2e
Years to Pay Back *	39.4 years

* Calculated as the ratio of the cost of insulating the boiler (difference 5" vs. 4" insulation) and the incremental cost savings in fuel savings when using 5" vs. 4" insulation.

Air Sciences Inc.	PROJECT TITLE: Solvay Package Boiler		BY: T. Martin	
AIR SCIENCES INC. ENGINEERING CALCULATIONS	PROJECT NO: 170-12-2	PAGE: 3	OF: 4	SHEET:
	SUBJECT: GHG Insulation Costs	DATE: July 31, 2012		

INCREMENTAL COST CALCULATIONS FOR BOILER INSULATION: 5" INSULATION VS. 6" INSULATION

Assumptions	Units	Reference
Natural gas thermal equivalent	1,020 Btu/scf	AP-42, Section 1.4 (Revision 7/98)
Area of Insulation	2,530 ft^2	Solvay
Boiler Heat Loss	187,700 $BTU/ft^2/yr$	Solvay - 5" thick insulation
	158,000 $BTU/ft^2/yr$	Solvay - 6" thick insulation
Cost of Natural Gas	2.34 \$/thousand ft^3	Solvay - current hub price
	0.00234 \$/ ft^3	
	435,897 Btu/\$	
	0.4359 MMBtu/\$	
Cost of Insulation	\$24.15 \$/ ft^2	Solvay - cost of 5" thick insulation*
	\$25.35 \$/ ft^2	Solvay - cost of 6" thick insulation*
Cost of Insulating Boiler	\$61,100	Solvay - cost of 5" thick insulation*
	\$64,136	Solvay - cost of 6" thick insulation*
	\$3,036 one time cost	Difference (5" vs. 6")
	\$121 \$/yr ,annualized cost over assumed 20-year life of boiler**	

* Insulation material will be 8# mineral wool with aluminum jacket.

CALCULATIONS

Parameter	Units
Heat Loss	
5" Insulation	474.9 MMBtu/yr
6" Insulation	399.7 MMBtu/yr
Reduction in Heat Loss (5" vs. 6")	75.1 MMBtu/yr
Cost of Lost Heat (in terms of Natural Gas)	
5" Insulation	\$1,089 \$/yr
6" Insulation	\$917 \$/yr
Incremental Cost Savings (5" vs. 6")	\$172 \$/yr
Combined annualized insulation cost and fuel savings	-\$51 \$/yr
GHG Emissions Reduction (5" vs. 6")	4.39 GHG Mass (tpy)
	4.40 CO_2e (tpy)
Incremental Cost to Insulate to 6" (fuel savings not considered)	\$28 \$/ton GHG Mass
	\$28 \$/ton GHG CO2e
Incremental Cost to Insulate to 6" (with fuel savings considered)	-\$12 \$/ton GHG Mass
	-\$12 \$/ton GHG CO2e
Years to Pay Back *	17.6 years

* Calculated as the ratio of the cost of insulating the boiler (difference 5" vs. 6" insulation) and the incremental cost savings in fuel savings when using 5" vs. 6" insulation.

Air Sciences Inc. ENGINEERING CALCULATIONS	PROJECT TITLE: Solvay Package Boiler	BY: T. Martin		
	PROJECT NO: 170-12-2	PAGE: 4	OF: 4	SHEET:
	SUBJECT: GHG Insulation Costs	DATE: July 31, 2012		

AIR SCIENCES INC

INCREMENTAL COST CALCULATIONS FOR BOILER INSULATION: 3" INSULATION VS. 6" INSULATION

Assumptions	Units	Reference
Natural gas thermal equivalent	1,020 Btu/scf	AP-42, Section 1.4 (Revision 7/98)
Area of Insulation	2,530 ft^2	Solvay
Boiler Heat Loss	301,800 BTU/ft^2/yr	Solvay - 3" thick insulation
	158,000 BTU/ft^2/yr	Solvay - 6" thick insulation
Cost of Natural Gas	2.34 \$/thousand ft^3	Solvay - current hub price
	0.00234 \$/ ft^3	
	435,897 Btu/\$	
	0.4359 MMBtu/\$	
Cost of Insulation	\$19.00 \$/ ft^2	Solvay - cost of 3" thick insulation*
	\$25.35 \$/ ft^2	Solvay - cost of 6" thick insulation*
Cost of Insulating Boiler	\$48,070	Solvay - cost of 3" thick insulation*
	\$64,136	Solvay - cost of 6" thick insulation*
	\$16,066 one time cost	Difference (6" vs. 3")
	\$643 \$/yr ,annualized cost over assumed 20-year life of boiler**	

* Insulation material will be 8# mineral wool with aluminum jacket.

CALCULATIONS

Parameter	Units
Heat Loss	
3" Insulation	763.6 MMBtu/yr
6" Insulation	399.7 MMBtu/yr
Reduction in Heat Loss (6" vs. 3")	363.8 MMBtu/yr
Cost of Lost Heat (in terms of Natural Gas)	
3" Insulation	\$1,752 \$/yr
6" Insulation	\$917 \$/yr
Incremental Cost Savings (6" vs. 3")	\$835 \$/yr
Combined annualized insulation cost and fuel savings	-\$192 \$/yr
GHG Emissions Reduction (6" vs. 3")	21.26 GHG Mass (tpy)
	21.28 CO_2e (tpy)
Incremental Cost to Insulate to 6" (fuel savings not considered)	\$30 \$/ton GHG Mass
	\$30 \$/ton GHG CO2e
Incremental Cost to Insulate to 6" (with fuel savings considered)	-\$9 \$/ton GHG Mass
	-\$9 \$/ton GHG CO2e
Years to Pay Back *	19.2 years

* Calculated as the ratio of the cost of insulating the boiler (difference 6" vs. 3" insulation) and the incremental cost savings in fuel savings when using 6" vs. 3" insulation.

Appendix F: US Fish and Wildlife Service - List of Threatened and Endangered Species

United States Department of the Interior

FISH AND WILDLIFE SERVICE
WYOMING ECOLOGICAL SERVICES FIELD OFFICE
5353 Yellowstone Rd, Suite 308A
CHEYENNE, WY 82009
PHONE: (307)772-2374 FAX: (307)772-2358
URL: www.fws.gov/wyominges/

Consultation Tracking Number: 06E13000-2012-SLI-0295 July 05, 2012
Project Name: Solvay Chemicals, Inc.

Subject: List of threatened and endangered species that may occur in your proposed project location, and/or may be affected by your proposed project.

To Whom It May Concern:

The enclosed species list identifies threatened, endangered, and proposed species, designated critical habitat, and candidate species that may occur within the boundary of your proposed project and/or may be affected by your proposed project. The species list fulfills the requirements of the U.S. Fish and Wildlife Service (Service) under section 7(c) of the Endangered Species Act (Act) of 1973, as amended (16 U.S.C. 1531 et seq.).

New information based on updated surveys, changes in the abundance and distribution of species, changed habitat conditions, or other factors could change this list. Please note that under 50 CFR 402.12(e) of the regulations implementing section 7 of the Act, the accuracy of this species list should be verified after 90 days. This verification can be completed formally or informally as desired. The Service recommends that verification be completed by visiting the Environmental Conservation Online System-Information, Planning, and Conservation System (ECOS-IPaC) website at regular intervals during project planning and implementation for updates to species lists and information. An updated list may be requested through the ECOS-IPaC system by completing the same process used to receive the enclosed list.

Please feel free to contact us if you need more information or assistance regarding the potential impacts to federally proposed, listed, and candidate species and federally designated and proposed critical habitat. We also encourage you to visit the Wyoming Ecological Services website at http://www.fws.gov/wyominges/Pages/Species/Species_Endangered.html for more information about species occurrence and designated critical habitat.

The purpose of the Act is to provide a means whereby threatened and endangered species and the ecosystems upon which they depend may be conserved. Under sections 7(a)(1) and 7(a)(2) of the Act and its implementing regulations (50 CFR 402 et seq.), Federal agencies are required to use their authorities to carry out programs for the conservation of threatened and endangered species and to determine whether projects may affect threatened and endangered species and/or designated critical habitat.

A biological assessment is required for construction projects (or other undertakings having similar physical impacts) that are major Federal actions significantly affecting the quality of the human environment as defined in the National Environmental Policy Act (42 U.S.C. 4332(2)(c)). For projects other than major construction activities, the Service suggests that a biological evaluation similar to a biological assessment be prepared to determine whether the project may affect listed or proposed species and/or designated or proposed critical habitat. Recommended contents of a biological assessment are described at 50 CFR 402.12.

If a Federal agency determines, based on the biological assessment or biological evaluation, that listed species and/or designated critical habitat may be affected by the proposed project, the agency is required to consult with the Service pursuant to 50 CFR 402. In addition, the Service recommends that candidate species, proposed species, and proposed critical habitat be addressed within the consultation. More information on the regulations and procedures for section 7 consultation, including the role of permit or license applicants, can be found in the "Endangered Species Consultation Handbook" at:
http://www.fws.gov/endangered/esa-library/pdf/TOC-GLOS.PDF

We also recommend that you consider the following information when assessing impacts to federally listed species, as well as migratory birds, and other trust resources:

Colorado River and Platte River Systems: Consultation under section 7 of the Act is required for projects in Wyoming that may lead to water depletions or have the potential to impact water quality in the Colorado River system or the Platte River system, because these actions may affect threatened and endangered species inhabiting the downstream reaches of these river systems. In general, depletions include evaporative losses and/or consumptive use of surface or groundwater within the affected basin, often characterized as diversions minus return flows. Project elements that could be associated with depletions include, but are not limited to: ponds, lakes, and reservoirs (e.g., for detention, recreation, irrigation, storage, stock watering, municipal storage, and power generation); hydrostatic testing of pipelines; wells; dust abatement; diversion structures; and water treatment facilities.

Species that may be affected in the Colorado River system include the endangered bonytail (*Gila elegans*), Colorado pikeminnow (*Ptychocheilus lucius*), humpback chub (*Gila cypha*), and razorback sucker (*Xyrauchen texanus*) and their designated critical habitats. Projects in the Platte River system may impact the endangered interior population of the least tern (*Sterna antillarum*), the endangered pallid sturgeon (*Scaphirhynchus albus*), the threatened piping plover (*Charadrius melodus*), the threatened western prairie fringed orchid (*Platanthera praeclara*), as well as the endangered whooping crane (*Grus americana*) and its designated critical habitat. For more information on consultation requirements for the Platte River species, please visit http://www.fws.gov/platteriver.

Migratory Birds: The Migratory Bird Treaty Act (16 U.S.C. 703-712), prohibits the taking of any migratory birds, their parts, nests, or eggs except as permitted by regulations, and does not require intent to be proven. Except for introduced species and some upland game birds, almost all birds occurring in the wild in the United States are protected (50 CFR 10.13). Guidance for minimizing impacts to migratory birds for projects that include communications towers (e.g., cellular, digital television, radio, and emergency broadcast) can be found at http://www.fws.gov/migratorybirds/CurrentBirdIssues/Hazards/towers/towers.htm.

The Bald and Golden Eagle Protection Act (16 U.S.C. 668-668d) prohibits knowingly taking, or taking with wanton disregard for the consequences of an activity, any bald or golden eagles or their body parts, nests, or eggs, which includes collection, molestation, disturbance, or killing. Eagle nests are protected whether they are active or inactive. Removal or destruction of nests, or causing abandonment of a nest could constitute a violation of one or both of the above statutes. Projects affecting eagles may require development of an eagle conservation plan (http://www.fws.gov/windenergy/eagle_guidance.html). Additionally, wind energy projects should follow the wind energy guidelines (http://www.fws.gov/windenergy/) for minimizing impacts to migratory birds and bats.

If nesting migratory birds are present on or near the project area, timing of activities is an important consideration and should be addressed in project planning. Activities that could lead to the take of migratory birds or eagles, their young, eggs, or nests, should be coordinated with our office prior to project implementation. If nest manipulation (including removal) is proposed for the project, the project proponent should contact the Migratory Bird Office in Denver at 303-236-8171 to see if a permit can be issued for the project. If a permit cannot be issued, the project may need to be modified to protect migratory birds, eagles, their young, eggs, and nests.

We appreciate your concern for threatened and endangered species. The Service encourages Federal agencies to include conservation of threatened and endangered species into their project planning to further the purposes of the Act. Please include the Consultation Tracking Number in the header of this letter with any request for consultation or correspondence about your project that you submit to our office.

Attachment

United States Department of Interior
Fish and Wildlife Service

Project name: Solvay Chemicals, Inc.

Official Species List

Provided by:

WYOMING ECOLOGICAL SERVICES FIELD OFFICE
5353 Yellowstone Rd, Suite 308A

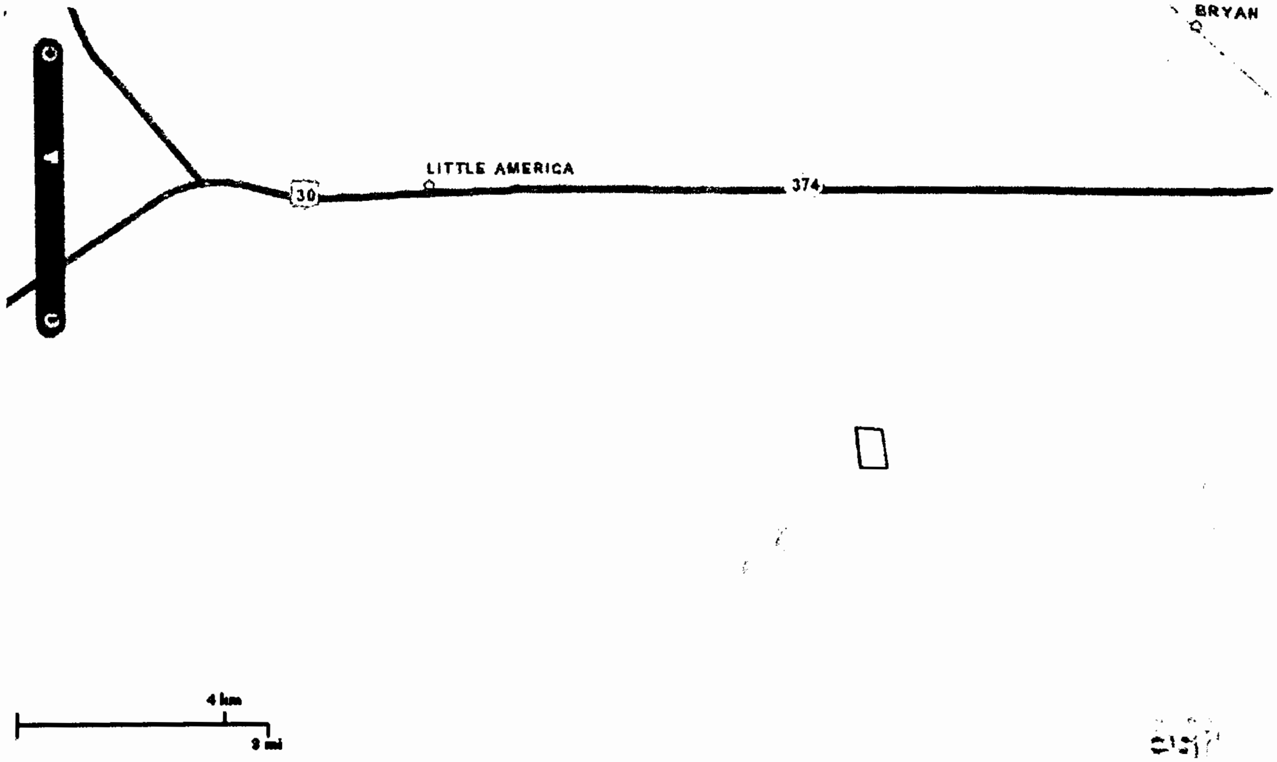
CHEYENNE, WY 82009
(307) 772-2374
http://www.fws.gov/wyominges/

Consultation Tracking Number: 06E13000-2012-SLI-0295
Project Type: Mining
Project Description: Addition of 253MMBtu/hr gas fired boiler to existing processing facility.

United States Department of Interior
Fish and Wildlife Service

Project name: Solvay Chemicals, Inc.

Project Location Map:



Project Coordinates: MULTIPOLYGON (((-109.7610494 41.502183, -109.7552902 41.5020094, -109.7541229 41.4953367, -109.7602426 41.4952403, -109.7610494 41.502183)))

Project Counties: Sweetwater, WY

United States Department of Interior
Fish and Wildlife Service

Project name: Solvay Chemicals, Inc.

Endangered Species Act Species List

Species lists are not entirely based upon the current range of a species but may also take into consideration actions that affect a species that exists in another geographic area. For example, certain fish may appear on the species list because a project could affect downstream species. Please contact the designated FWS office if you have questions.

Black-Footed ferret *(Mustela nigripes)*

Population: entire population, except where EXPN

Listing Status: Endangered

Blowout penstemon *(Penstemon haydenii)*

Listing Status: Endangered

Bonytail chub *(Gila elegans)*

Population: entire

Listing Status: Endangered

Colorado pikeminnow *(Ptychocheilus lucius)*

Population: except Salt and Verde R. drainages, AZ

Listing Status: Endangered

Greater sage-grouse *(Centrocercus urophasianus)*

Population: entire

Listing Status: Candidate

Humpback chub *(Gila cypha)*

Population: entire

Listing Status: Endangered

Razorback sucker *(Xyrauchen texanus)*

Population: entire

Listing Status: Endangered

Ute ladies'-tresses *(Spiranthes diluvialis)*

Listing Status: Threatened

Yellow-Billed Cuckoo *(Coccyzus americanus)*

Population: Western U.S. DPS

Listing Status: Candidate