State of Idaho
Department of Environmental Quality
Air Quality Division

AIR QUALITY PERMIT
STATEMENT OF BASIS

Permit to Construct No. P-2009.0127

Final

Southeast Idaho Energy, LLC

Power County Advanced Energy Center

American Falls, Idaho

Facility ID No. 077-00029

November 30, 2009

Morrie Lewis

Permit Writer

The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.200, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

acfm	actual cubic feet per minute
AFS	AIRS Facility Subsystem
AGR	acid gas removal
AIRS	Aerometric Information Retrieval System
AQCR	Air Quality Control Region
AQMD	Air Quality Management District
ASTM	American Society for Testing and Materials
ASU	air separation unit
BACT	Best Available Control Technology
BMP	best management practices
Btu	British thermal units
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEMS	continuous emission monitoring system
CFR	Code of Federal Regulations
CH_4	methane
CI	compression-ignition
CMS	continuous monitoring system
CO	carbon monoxide
CO_2	carbon dioxide
COS	carbonyl sulfide
DEQ	Idaho Department of Environmental Quality
EPA	U.S. Environmental Protection Agency
FGR	flue gas recirculation
H_2	hydrogen
H_2S	hydrogen sulfide
HAP	Hazardous Air Pollutants
ICE	internal combustion engine
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
km	kilometers
kW	kilowatts
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
MACT	Maximum Achievable Control Technology
MMBtu	millions of British thermal units
MRR	monitoring, recordkeeping, and reporting
MW or MW_e	megawatts of electrical output
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	ammonia
NO_2	nitrogen dioxide
N_2O	nitrous oxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	oxygen
O&M	operations and maintenance
OxCat	oxidation catalyst
PCAEC	Power County Advanced Energy Center
PEMS	predictive emission monitoring system

petcoke	petroleum coke
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
ppm	parts per million
ppmv	parts per million by volume
P&ID	piping and instrumentation diagrams
PSA	pressure swing adsorber
PSD	Prevention of Significant Deterioration
PTC	permit to construct
RICE	reciprocating internal combustion engine
Rules	Rules for the Control of Air Pollution in Idaho
scf	standard cubic feet
SCR	selective catalytic reduction
SIC	Standard Industrial Classification
SIE	Southeast Idaho Energy, LLC
SIP	State Implementation Plan
SO_2	sulfur dioxide
SO_x	sulfur oxides
SRC##	emission source number
syngas	synthesis gas
T/yr	tons per year
UAN	urea ammonium nitrate
UTM	Universal Transverse Mercator
VOC	volatile organic compounds
ZLDS	zero liquid discharge system

FACILITY INFORMATION

Description

The Power County Advanced Energy Center (PCAEC) will be located in Power County, approximately 4 kilometers (km) southwest of American Falls and 45 km southwest of Pocatello. The facility will produce fertilizer products through the gasification of coal and petcoke. Gasification is a process in which carbon, hydrogen, and water react with oxygen in a large high-pressure vessel to form synthesis gas, or syngas. Syngas is primarily a mixture of carbon monoxide (CO), carbon dioxide (CO_2), and hydrogen (H_2). Sulfur compounds and water vapor are also present in the syngas. The CO_2 and H_2 components are the building blocks used to manufacture the fertilizer products. A pure H_2 stream is used to manufacture ammonia (NH_3), which is used to produce other nitrogen-based fertilizers.

The paragraphs in each permit section provide an overview of the facility, sources of emissions, and emission control technologies.

Permitting History

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

February 10, 2009 PTC No. P-2008.0066, initial permit to construct. (S)

Application Scope

This is a revised permit to construct (PTC) to incorporate permit conditions requested by the applicant and based on a settlement agreement between the applicant and the Sierra Club and the Idaho Conservation League.

DEQ has included a CO_2 emissions limit and supporting requirements for the control of an unregulated air contaminant. DEQ has affirmed that such action has been undertaken at the request of the applicant and will not be considered precedent-setting or adopted at this time as standard DEQ policy or procedure.

EPA does not currently consider CO_2 to be a “regulated NSR pollutant” as defined in 40 CFR 52.21(b)(50), and DEQ does not currently consider CO_2 to be a regulated air pollutant (IDAPA 58.01.01.006.95) or a state-only toxic air pollutant (IDAPA 58.01.01.006.120).

A summary of the requested revisions (the proposed project) have been listed after each affected emissions source below.

<u>Feedstock Specifications</u>

- Allow the use of alternative feedstocks without increasing permitted throughput or emissions.

<u>Gasification Island</u>

- Limit the number of gasification island startups when using coal/petcoke.
- Include the use of sulfur-free alcohol-based fuels for gasification island startups as an alternative to coal/petcoke.

<u>Boilers</u>

- Reduce the NO_X emissions limits from the steam superheater and package boilers.
- Reduce the CO emissions limits from the steam superheater and package boilers.
- Install and operate an oxidation catalyst in addition to SCR on the steam super-heater and package boilers.

Fugitive Component Leaks

- Limit fugitive emissions and require monitoring and best management practices for the control of fugitive CO emissions from the outlet of the gasifier to the outlet of the final shift reactor.
- Install and operate a continuous emissions monitoring system (CEMS) to monitor the emissions of carbon monoxide (CO).

PM from AN Neutralizer Vent

- Install and operate drift and mist eliminators and a condenser on the Ammonium Nitrate neutralizer vent for the control of PM emissions.
- Perform an initial performance test to measure total PM.

Nitric Acid Plant

- Install and operate an extended absorption tower in addition to SCR on the Nitric Acid Plant.
- Reduce the N_2O emissions limit from the Nitric Acid Plant.
- Reduce NO_X emissions from the Nitric Acid Plant.

Acid Gas Removal

- Limit CO_2 emissions from the AGR stream CO_2 vent.

Application Chronology

February 10, 2009	DEQ issued PTC No. P-2008.0066.
March 17, 2009	The Sierra Club, the Idaho Conservation League, and the Shoshone-Bannock Tribes petitioned for a contested case proceeding seeking review of PTC No. P-2008.0066.
September 23, 2009	DEQ was provided a copy of a settlement agreement reached between the applicant, the Sierra Club, and the Idaho Conservation League.
September 30, 2009	DEQ held a pre-application meeting with the applicant to discuss the proposed additional permit requirements outlined in the settlement agreement, including the request to include CO_2 emissions limits.
October 6, 2009	DEQ notified the applicant that the requested CO_2 emissions limits could be incorporated in a revised PTC. DEQ affirmed that such action would be undertaken at the request of the applicant and would not be considered precedent-setting or adopted as standard DEQ policy or procedure.
October 19, 2009	DEQ received an application to revise PTC No. P-2008.0066 based on the additional permit requirements identified in the settlement agreement and supporting documentation.
October 19, 2009	DEQ received an application fee and a permit processing fee.
October 19, 2009	DEQ requested additional information from the applicant.
October 27, 2009	DEQ made available the draft permit and statement of basis for peer review.
October 29, 2009	DEQ received additional information from the applicant concerning alternative feedstocks and sulfur-free fuels.
November 2, 2009	DEQ made available the draft permit and statement of basis for applicant review.
November 13, 2009	DEQ made available the draft permit and statement of basis for review by the Sierra Club and the Idaho Conservation League.
November 30, 2009	DEQ issued the final permit and statement of basis.

TECHNICAL ANALYSIS

Emissions Units and Control Devices

Table 1 EMISSIONS UNITS AND CONTROL DEVICES INFORMATION

Permit Section	Source Descriptions	Control Equipment Descriptions
3	Feedstocks and Fluxant Storage and Handling	Enclosures Baghouses Covered conveyors and transition points Water Sprays or equivalent (fluxant only) BMP for fugitive PM/PM_{10}
4	Natural Gas-Fired Heaters ASU Regen Heater Gasifier Heaters #1 and #2	None
5	Diesel-fired Emergency Generators 2 MW Emergency Generator 500 kW Emergency Generator (Fire Pump)	None
6	Steam Superheater Boiler Package Boiler (used for startup and shutdown only)	Low-NO_X burner, SCR, and OxCat Low-NO_X burner, FGR, SCR, and OxCat
7	Gasification Island Startup: Sour Water Scrubber Activated Carbon Beds Normal Operations: Sour Water Scrubber Activated Carbon Beds AGR Stream 1: Claus Sulfur Recovery Unit AGR Stream 2: CO_2 Vent AGR Stream 3: Syngas	 Startups: Amine Scrubber (used for up to 13 startups on coal or petcoke) Gasifier Flare BMP for fugitive CO AGR Stream 1: None (no emission points) AGR Stream 2: Thermal Oxidizer AGR Stream 3: None (no emission points)
8	Ammonia and Urea Plants (purge gases)	Process Flare
8	Urea Melt Plant Vent Stack	None
8	Urea Granulation Wet Scrubber	Drift and mist eliminators
9	Nitric Acid Plant, tailgas	Extended absorption and SCR for NO_X Catalytic decomposition for N_2O
9	Ammonium Nitrate/ UAN Plant Wet Scrubber	Drift and mist eliminators and condenser
10	Diesel, Nitric Acid, and UAN Tank Storage	None
10	Ammonia Tank Storage	Ammonia Storage Flare
11	ZLDS and Cooling Tower	Drift/mist eliminators
12	Slag Storage and handling	Transferred from process wet into 3-sided bunker BMP for fugitive PM/PM_{10}
12	Granular urea storage, transfers, and loadout	Humidity-controlled warehouse storage
12	Elemental sulfur storage	None

Emissions Inventories and Ambient Air Impact Analyses

DEQ reviewed the emissions inventories and ambient air impact analyses submitted by the applicant for the initial permit to construct this facility, PTC No. P-2008.0066. As described in the statement of basis for PTC No. P-2008.0066, the emissions inventories and ambient air impact analyses submitted were considered conservative estimates based on DEQ review.

Because the proposed changes are not expected to result in any facility-wide emissions increase, or result in any emissions increase from any pollutant emissions source, or result in the emission of any regulated air pollutant not previously emitted, the emission inventories and ambient air impact analyses submitted for PTC No. P-2008.0066 have been considered adequate and have not been revisited, and additional analysis has not been required.

The applicant has demonstrated pre-construction compliance to DEQ's satisfaction that emissions from this facility will not cause or significantly contribute to a violation of any ambient air quality standard. The applicant has also demonstrated pre-construction compliance to DEQ's satisfaction that the emissions increase (or in this case, decrease) due to this permitting action will not exceed any acceptable ambient concentration or acceptable ambient concentration for carcinogens for toxic air pollutants.

It should be noted that the applicant has not requested offsetting or netting of any emissions reductions achieved for regulated air pollutants as a result of this permitting action. However, because more stringent and additional emission limits, control devices, work practices, and monitoring have been required by this permitting action, the emission inventories and ambient air impact analyses submitted for PTC No. P-2008.0066 have been considered conservative estimates of the permitted emissions and the expected ambient air quality impacts from emissions sources at this facility as a result of this permitting action. Refer to the statement of basis issued with PTC No. P-2008.0066 for additional information and engineering analysis of the emission inventories and the ambient air impact analyses for PTC No. P-2008.0066.

Attainment Designation (40 CFR 81.313)

The facility is located in Power County, which is designated as attainment or unclassifiable for $PM_{2.5}$, PM_{10}, SO_2, NO_2, CO and ozone; as specified in 40 CFR 81.313.

Permit to Construct (IDAPA 58.01.01.201)

The applicant submitted an application requesting a revised PTC to incorporate additional permit conditions. Therefore, this permitting action was processed in accordance with the procedures of IDAPA 58.01.01.200-228.

Tier II Operating Permit (IDAPA 58.01.01.401)

The applicant submitted an application requesting a revised PTC to incorporate additional permit conditions, and an optional Tier II operating permit was not requested. Therefore, the procedures of IDAPA 58.01.01.400–410 were not applicable to this permitting action.

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

The applicant submitted an application requesting a revised PTC to incorporate additional permit conditions. Therefore, the requirements of IDAPA 58.01.01.300–399 were not applicable to this permitting action.

The facility is classified as a major facility, as defined in IDAPA 58.01.01.008.10. The facility has the potential to emit greater than 100 tons per year each of NO_X and CO. Therefore, in accordance with IDAPA 58.01.01.313.01.b, the permittee must submit a complete application to DEQ for an initial Tier I operating permit within 12 months of becoming a Tier I source or commencing operation.

PSD Classification (40 CFR 52.21)

The facility is a designated facility as defined in 40 CFR 52.21(b)(1)(i)(a) and IDAPA 58.01.01.006.30, included as a fuel conversion plant and as a chemical process plant in the list of 28 sources. As a result, fugitive emissions must be included when determining the potential to emit in accordance with 40 CFR 52.21(b)(1)(iii).

The facility is classified as an existing major stationary source, because the estimated emissions of NO_X and CO each have the potential to exceed major stationary source thresholds of 100 T/yr. Because the facility is major for NO_X, it is also considered major for ozone, in accordance with 40 CFR 52.21(b)(1)(ii). BACT determinations were made for regulated emissions sources in the initial permit to construct for PM, PM_{10}, NO_X, and CO pollutants (refer to Section 4.11 in the statement of basis for PTC No. P-2008.0066).

It should be noted that certain requested revisions involved best available control technology (BACT) requirements. Specific information has been provided for each BACT permit condition which has been revised within the permit condition review section that follows. A summary of the revisions made to the BACT emissions limits and supporting monitoring, recordkeeping, and reporting requirements (MRR) has been included in Table 2 below.

As defined in 40 CFR 52.21(b)(12), BACT means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation which would be emitted from any proposed major stationary source or major modification which DEQ, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If DEQ determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

EPA has developed[1], and DEQ has implemented, a "top-down" process to ensure that a BACT review satisfies applicable legal criteria. The BACT review consists of a five-step process which provides that all available control technologies be ranked in descending order of control effectiveness, beginning with the most stringent. The most stringent control technology is deemed the control necessary to achieve BACT emission limits unless the applicant demonstrates, and DEQ determines, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not “achievable” in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on. An incomplete BACT analysis, including failure to consider all potentially applicable control alternatives, constitutes an incomplete application. The five general steps in the BACT review process are summarized as follows:

1) Identify all control technologies
2) Eliminate technically infeasible options
3) Rank remaining control technologies by control effectiveness
4) Evaluate the most effective controls considering economic, environmental, and energy impacts
5) Select BACT

Although EPA and DEQ regulations do not specifically require application of this process to meet PSD regulatory requirements, this top-down analysis ensures that a defensible BACT determination, including consideration of all requisite statutory and regulatory criteria, is reached.

[1] EPA Draft NSR Workshop Manual, October 1990.

Concerning the requested revisions, for each BACT selection, emissions limit, and supporting requirements from PTC No. P-2008.0066 which have been revised, DEQ determined that a detailed reevaluation of the original BACT determination was not warranted, based on the following observations:

- The requested revisions do not result in any change to PSD applicability. Each pollutant emissions unit retains the same applicability status at the facility. A PSD applicability analysis has been included below.
- In each case, the "top" available control technology of the technologies identified was selected (step one in the recommended "top-down" approach, before the elimination of any technologies). Using this approach, the selected control technology and emissions limit may be comparable in some cases to the lowest achievable emissions rate limit.
- In each case, the control technology selection from the original BACT determination was retained. In the case of the nitric acid plant, a process equipment change (extended absorption tower) was identified in addition to the original control technology selection, in order to achieve more stringent NO_X emissions limits. Although this "combination" of controls was not identified or evaluated within the original BACT review, under such circumstances the combined control option would have been ranked as the "top" available control option. It was therefore deemed unnecessary to revisit the detailed BACT review provided in the statement of basis for PTC No. P-2008.0066.
- In each case, the revised BACT emissions limits associated with the selected control technology were more stringent than the original BACT emissions limits. A comparison of the relevant changes has been summarized in Table 2 below.
- In each case, the original MRR requirements developed to ensure compliance with the BACT emissions limits were retained. In cases where additional emissions limits or equipment were required, additional MRR requirements were considered;
  - In the case of implementing the extended absorption tower in the nitric acid plant, because the process change occurs upstream of the control device/emissions point, additional requirements beyond including the tower in the development of the O&M Plan (Permit Condition 2.3) were deemed unnecessary.
  - In the case of implementing the 31 T/yr fugitive emissions limit for fugitive CO emissions, additional work practice requirements were required to be included in the Fugitive CO BMP Plan (Permit Condition 7.13) to demonstrate compliance with the fugitive emissions limit.
  - In the case of implementing the 0.60 lb/ton limit in the nitric acid plant, the requirement to install, calibrate, maintain, and operate a CEMS for measuring NO_X emissions from the nitric acid production unit (Permit Condition 9.7) and supporting requirements were considered adequate to demonstrate continuous compliance with each NO_X emissions limit.
- The requested revisions have not introduced new or additional energy, environmental, or economic impacts or costs which would warrant reconsideration of the technology selection. For each pollutant emissions source, the requested revisions are not expected to result in any emissions increase or in the emission of any regulated air pollutant not previously emitted. This includes the request to use alternative feedstocks; the applicant has requested the use of renewable resources as fuel to minimize the emissions of CO_2. Although CO_2 emissions are not regulated, this could be characterized as an environmental benefit. Refer to the additional discussion provided in the application scope section and for Permit Condition 2.16 in the permit condition review section.
- In each case, the proposed changes resulted from new or refined engineering analysis, and have not been considered the result of noncompliance. There has been no indication that the applicant has intentionally acted to misrepresent or conceal data in the application and BACT analysis submitted for PTC No. P-2008.0066.

Table 2 SUMMARY OF BACT LIMIT REVISIONS[a]

Pollutant	Emissions Source	Revised Permit Conditions	Original Control Technology	Revised Control Technology	Original Emissions Limit	Revised Emissions Limits
NO_X	Steam superheater and package boilers	6.3	SCR	SCR	0.02 lb/MMBtu	0.006 lb/MMBtu
					5.0 lb/hr	1.5 lb/hr
					21.9 T/yr	6.6 T/yr
	Nitric acid plant	9.3, 9.5, 2.3	SCR	Extended absorption + SCR	50 ppmv	50 ppmv
						0.60 lb/ton
					15.3 lb/hr	14.4 lb/hr
					67.2 T/yr	63.0 T/yr
CO	Fugitive CO emissions	7.4, 7.13	BMP Plan	BMP Plan	BMP Plan	BMP Plan
						31 T/yr (fugitive)

a) “Original” requirements are based on the requirements in PTC No. P-2008.0066. “Revised” requirements are based on the requirements in PTC No. P-2009.0127.

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

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

In accordance with 40 CFR 52.21(a)(2)(i), the requirements of this section apply to the construction of any new major stationary source or any project at an existing major stationary source in an area designated as attainment or unclassifiable. This project is proposed at an existing major stationary source in an area designated as attainment or unclassifiable (refer to the attainment designation section).

In accordance with §52.21(a)(2)(ii), the requirements of paragraphs (j) through (r) of this section apply to the construction of any new major stationary source or the major modification of any existing major stationary source, except as otherwise provided. This project is not a major modification as defined in 40 CFR 52.21(b)(2)(i), because it does not result in a significant emissions increase in accordance with 40 CFR 52.21(b)(40). The estimated potential to emit of each pollutant from each emissions source, including fugitive emissions, is expected to remain the same or to decrease as a result of this project. Therefore, the requirements of paragraphs 40 CFR 52.21(j) through (r) do not apply to this project unless otherwise provided.

For the purposes of the definition of major modification in §52.21(b)(2)(iii)(*e*)(2), a physical change in the method of operation shall not include use of an alternative fuel or raw material by a stationary source which the source was approved to use under any permit issued under §52.21. As requested by the applicant, methanol and ethanol have been proposed in this project as alternative fuels for use during gasifier startups, and the alternative materials listed in Appendix A have been proposed in this project as alternative feedstocks for processing in the gasifiers.

In accordance with §52.21(a)(2)(iii), no new major stationary source or major modification to which the requirements of paragraphs (j) through (r)(5) of this section apply shall begin actual construction without a permit that states that the major stationary source or major modification will meet those requirements. As provided above, paragraphs (j) through (r)(5) are not applicable.

40 CFR 52.21(c).....................................Ambient air increments.

In accordance with §52.21(c), in areas designated as Class I, II or III, increases in pollutant concentration over the baseline concentration shall be limited to the values in the table provided.

As provided above, because emissions from each source are expected to remain the same or decrease as a result of this project, the ambient air impact analyses submitted for PTC No. P-2008.0066 have not been revised or revisited, and additional analysis has not been required.

40 CFR 52.21(d)....................................Ambient air ceilings.

In accordance with §52.21(d), no concentration of a pollutant shall exceed: (1) the concentration permitted under the national secondary ambient air quality standard, or (2) the concentration permitted under the national primary ambient air quality standard, whichever concentration is lowest for the pollutant for a period of exposure. The primary and secondary standards do not specifically include fluorides.

As provided above, because emissions from each source are expected to remain the same or decrease as a result of this project, the ambient air impact analyses submitted for PTC No.P-2008.0066 have not been revised or revisited, and additional analysis has not been required.

40 CFR 52.21(r).....................................Source obligation.

Applicable approval to construct and associated requirements are included in §52.21(r)(1) through (4).

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

As defined in §52.21(r)(6)(vi), a "reasonable possibility" under paragraph §52.21(r)(6) occurs when the owner or operator calculates the project to result in either: (*a*) a projected actual emissions increase of at least 50 percent of the amount that is a "significant emissions increase," as defined under paragraph §52.21(r)(b)(40) (without reference to the amount that is a significant net emissions increase), for the regulated NSR pollutant; or (*b*) a projected actual emissions increase that, added to the amount of emissions excluded under paragraph §52.21(r)(b)(41)(ii)(*c*), sums to at least 50 percent of the amount that is a "significant emissions increase," as defined under paragraph §52.21(r)(b)(40) (without reference to the amount that is a significant net emissions increase), for the regulated NSR pollutant.

The estimated potential to emit of each pollutant from each emissions source, including fugitive emissions, is expected to remain the same or to decrease as a result of this project (the facility has not yet commenced construction). Therefore, a reasonable possibility that the project may result in a significant emissions increase of any regulated air pollutant is not expected to occur as a result of the proposed project as defined in §52.21(r)(6)(vi).

NSPS Applicability (40 CFR 60)

The proposed revisions do not alter the applicability status of 40 CFR Part 60 affected facilities.

Because the package boiler and steam superheater will commence construction after June 19, 1984 and after February 28, 2005, and because each affected facility (boiler) will have a heat input capacity of greater than 29 MW/hr (250 MW/hr), each boiler will be subject to the provisions of 40 CFR 60, Subpart Db – Standards Of Performance For Industrial-Commercial-Institutional Steam Generating Units.

Because the nitric acid plant proposed for this project will be constructed after August 17, 1971, and will produce nitric acid at a concentration of approximately 57 percent, the requirements of 40 CFR 60, Subpart G – Standards of Performance for Nitric Acid Plants, are applicable to each nitric acid production unit at the facility.

Because the coal and petcoke grinder and rod mill can process more than 200 T/day (as much as 5,000 T/day) of coal/petcoke, and the coal preparation plant will be constructed after October 24, 1974, the affected facilities (thermal dryers, pneumatic coal-cleaning equipment, coal processing and conveying equipment, coal storage systems, and coal transfer and loading systems) are therefore subject to 40 CFR 60, Subpart Y – Standards of Performance for Coal Preparation Plants.

Because the proposed project will commence construction after November 8, 2006, and produces one urea as a final product, the proposed urea process is an affected facility subject to 40 CFR 60, Subpart VVa – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006. Based on EPA guidance[2], the "formaldehyde addition step" in producing granular urea has been considered to be the sole cause of potential fugitive VOC emissions from urea productions processes, and has been considered to be in VOC service.

Because the emergency generators will commence construction (be ordered) after July 11, 2005, and will be manufactured after April 1, 2006, the affected sources (generators) are subject to 40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (CI ICE)

Because the facility is subject to NSPS Subparts Db, and YY, the facility is also subject to 40 CFR Part 60, Subpart A – General Provisions.

NESHAP Applicability (40 CFR 61)

The emissions units described in Table 1 of the emissions units and control devices section are not included in any of the source categories subject to a National Emission Standard for Hazardous Air Pollutants (NESHAP). The facility is not subject to any NESHAP requirements in 40 CFR 61.

MACT Applicability (40 CFR 63)

The proposed revisions do not alter the applicability status of 40 CFR Part 63 affected emissions units at the facility.

The permittee is subject to 40 CFR Part 63, Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion (RICE) Engines, because the permittee has proposed to own or operate stationary RICE (two emergency diesel engine generators) at an area source of HAP emissions, and the proposed stationary RICE will be constructed after June 12, 2008. However, because both of the proposed emergency engine generators are subject to NSPS 40 CFR Part 60, Subpart IIII, the affected sources must meet the requirements of this part by meeting the requirements of Subpart IIII, in accordance with 40 CFR 63.6590(c).

The facility has been classified as a synthetic minor area source for HAP, because without limits on the potential to emit, carbonyl sulfide (COS) emissions have the potential to exceed the individual HAP major source threshold of 10 T/yr. The use of a thermal oxidizer on the AGR CO_2 vent is considered a federally enforceable limit (as defined in IDAPA 58.01.01.006.43) on the potential to emit COS. Without limits on the potential to emit, uncontrolled total HAP emissions from the facility have not been estimated to have the potential to exceed the total HAP major source threshold of 25 T/yr.

CAM Applicability (40 CFR 64)

The proposed revisions do not alter the applicability status of Compliance Assurance Monitoring (CAM) Part 64 affected emissions units at the facility.

The permittee must address CAM applicability within the initial Tier I permit application. Refer to the Title V classification section for additional information.

[2] EPA Applicability Determination, Control No. 0600015, Liquid Urea Manufacturing Operations, November 1, 2005.

Permit Conditions Review

This section describes only those permit conditions that have been added or revised as a result of this permitting action. DEQ has included a CO_2 emissions limit and supporting requirements for the control of an unregulated air contaminant. Please refer to the relevant discussion provided in the application scope section and for Permit Conditions 7.3, 7.5, 7.6, 7.7, 7.15, 7.16, 7.17, 7.18, and 7.19 below.

Revised Permit Conditions 1.4, 2.3, 6.3, and 6.10

The references to SCR in these permit conditions and descriptions have been revised to clarify that the SCR control device is used for the control of NO_X emissions from both the steam superheater boiler and the also the package boiler.

Revised Permit Conditions 1.4, 2.3, 3.2, 3.6, 4.2, 5.2, 6.2, 6.10, 7.2, 7.9, 8.2, 8.6, 9.2, 10.2, 11.2, 12.2

Because both process equipment and air pollution control equipment are used at this facility for the control of air pollution, and for purposes of clarification and consistency, the descriptive term “control equipment” has been used within these permit conditions.

Revised Permit Conditions 2.14, 2.15, 2.16, 3.1, 3.2, 3.3, 3.4, 3.6, 3.7, 3.8, 3.9, 7.2, 7.8, and 7.11

The references to feedstocks in these permit conditions and descriptions have been revised to include the use of alternative feedstocks in addition to coal and petcoke. Refer to the additional discussion provided in for Permit Conditions 2.16 and 3.7 below.

Existing Permit Condition 1.3

Table 1.1 lists all sources of regulated emissions in this PTC.

Table 1.1 SUMMARY OF REGULATED SOURCES

Permit Section	***Source Description***	***Emissions Control(s)***
3	*Coal, Petcoke, and Fluxant Storage and Handling*	*Enclosures* *Baghouses* *Covered conveyors and transition points* *Water Sprays or equivalent (fluxant only)* *BMPs for fugitive PM/PM_{10}*
4	*Natural Gas-Fired Heaters* *ASU Regen Heater* *Gasifier Heaters #1 and #2*	*None*
5	*Diesel-fired Emergency Generators* *2 MW Emergency Generator* *500 kW Emergency Generator (Fire Pump)*	*None*
6	*Package Boiler (used for startup and shutdown only)* *Steam Superheater Boiler*	*Low-NOx burner & FGR* *Low-NOx burner & SCR*
7	*Gasification Island* *Startup:* *Sour Water Scrubber (process equipment)* *Activated Carbon Beds (process equipment)* *Normal Operations:* *Sour Water Scrubber (process equipment)* *Activated Carbon Beds (process equipment)* *AGR Stream 1: Claus Sulfur Recovery Unit (process equipment)* *AGR Stream 2: CO_2 Vent* *AGR Stream 3: Syngas*	*Startups:* *Amine Scrubber* *Gasifier Flare* *BMPs for fugitive CO* *AGR Stream 1: None (no emission points)* *AGR Stream 2: Thermal Oxidizer* *AGR Stream 3: None (no emission points)*
8	*Ammonia and Urea Plants (purge gases)*	*Process Flare*
8	*Urea Melt Plant Vent Stack*	*None*
8	*Urea Granulation (wet scrubber is process equipment)*	*None*
9	*Nitric Acid Plant, tailgas*	*SCR for NO_x*
9	*Ammonium Nitrate/ UAN Plant (wet scrubber is process equipment)*	*None*
10	*Diesel, Nitric Acid, and UAN Tank Storage*	*None*

Table 1.1 SUMMARY OF REGULATED SOURCES

Permit Section	Source Description	Emissions Control(s)
10	Ammonia Tank Storage	Ammonia Storage Flare
11	ZLDS and Cooling Tower	Drift/mist eliminators
12	Slag Storage and handling	Transferred from process wet into 3-sided bunker BMPs for fugitive PM/PM_{10}
12	Granular urea storage, transfers, and loadout	Humidity-controlled warehouse storage
12	Elemental sulfur storage	None

Revised Permit Condition 1.4

Table 1.1 lists all sources of regulated emissions in this PTC.

Table 1.1 SUMMARY OF REGULATED SOURCES

Permit Section	Source Descriptions	Control Equipment Descriptions
3	Feedstocks and Fluxant Storage and Handling	Enclosures Baghouses Covered conveyors and transition points Water Sprays or equivalent (fluxant only) BMP for fugitive PM/PM_{10}
4	Natural Gas-Fired Heaters ASU Regen Heater Gasifier Heaters #1 and #2	None
5	Diesel-fired Emergency Generators 2 MW Emergency Generator 500 kW Emergency Generator (Fire Pump)	None
6	Steam Superheater Boiler Package Boiler (used for startup and shutdown only)	Low-NO_X burner, SCR, and OxCat Low-NO_X burner, FGR, SCR, and OxCat
7	Gasification Island Startup: Sour Water Scrubber Activated Carbon Beds Normal Operations: Sour Water Scrubber Activated Carbon Beds AGR Stream 1: Claus Sulfur Recovery Unit AGR Stream 2: CO_2 Vent AGR Stream 3: Syngas	 Startups: Amine Scrubber (used for up to 13 startups on coal or petcoke) Gasifier Flare BMP for fugitive CO AGR Stream 1: None (no emission points) AGR Stream 2: Thermal Oxidizer AGR Stream 3: None (no emission points)
8	Ammonia and Urea Plants (purge gases)	Process Flare
8	Urea Melt Plant Vent Stack	None
8	Urea Granulation Wet Scrubber	Drift and mist eliminators
9	Nitric Acid Plant, tailgas	Extended absorption and SCR for NO_X Catalytic decomposition for N_2O
9	Ammonium Nitrate/ UAN Plant Wet Scrubber	Drift and mist eliminators and condenser
10	Diesel, Nitric Acid, and UAN Tank Storage	None
10	Ammonia Tank Storage	Ammonia Storage Flare
11	ZLDS and Cooling Tower	Drift/mist eliminators
12	Slag Storage and handling	Transferred from process wet into 3-sided bunker BMP for fugitive PM/PM_{10}
12	Granular urea storage, transfers, and loadout	Humidity-controlled warehouse storage
12	Elemental sulfur storage	None

As requested by the applicant, this permit condition has been revised to include the use of an oxidation catalyst control device for the control of CO emissions from the steam superheater and package boilers; to clarify that the amine scrubber is to be used for up to 13 startups on coal/petcoke for the gasification island; to include the use of extended absorption in addition to SCR for the control of NO_X emissions from the nitric acid plant; to include the use of catalytic decomposition for the control of N_2O emissions from the nitric acid plant; and to include the use of drift and mist eliminators and a condenser for the control of particulate emissions from the ammonium nitrate neutralizer vent. A discussion of revisions related to SCR and feedstock descriptions has been provided at the beginning of this section.

The inclusion of drift and mist eliminators and a condensing system has been requested by the applicant for clarification purposes. The original project design and the emissions estimates assumed the use of this equipment, which was considered as process equipment in the original application.

Revised Permit Condition 2.2

The references in this permit condition have been revised to include the correct references to the Fugitive CO BMP Plan and the SSM plan permit conditions.

Existing Permit Condition 2.3

At least 60 days before initial start-up of each pollution control device, the permittee shall have developed and submitted to DEQ for review and comment an Operations and Maintenance (O&M) manual that describes the procedures that will be followed to comply with General Provision 2 of this permit and the manufacturer specifications for these air pollution control devices:

- *Baghouses are used to control particulate emissions from rail unloading, handling, and storage of feedstocks. If bag leak detection systems are not provided, the O&M manual shall contain requirements for monthly see/no see visible emissions inspections of the baghouses. The inspections shall occur during daylight hours and under normal operating conditions. Visible emissions inspections for silo baghouses shall be conducted while material is being transferred at normal operating rates into the silo(s). If bag leak detection systems are used, the manual shall include appropriate provisions for inspection, maintenance, and testing of these systems.*
- *Fluxant water spray system(s) (if used), including alternative practices to be used during freezing conditions;*
- *Flue gas recirculation (FGR) system for reducing NOx from the package boiler;*
- *Selective catalytic reduction (SCR) system for reducing NOx from the steam superheater boiler;*
- *Sour water scrubber for removing trace metals and sulfides from the syngas;*
- *Activated carbon beds for removing mercury from the syngas (process equipment);*
- *Amine scrubber used to decrease sulfur compounds in the syngas prior to flaring in the Gasifier Flare;*
- *Flares, including the:*
    - *Gasifier flare,*
    - *Process flare serving the ammonia and urea production plants, and the*
    - *Ammonia storage flare.*
- *Thermal oxidizer used to treat remaining H_2S, COS, and CO in the CO_2-rich stream from the AGR (AGR Stream 2);*
- *NO_X SCR system serving the nitric acid plant;*
- *Ammonium nitrate neutralizer scrubber (process equipment); and the*
- *Urea granulation process scrubber (process equipment) used to control PM/PM_{10} emissions.*

Revised Permit Condition 2.3

At least 60 days before the initial start-up of each of the following control equipment, the permittee shall have developed and submitted to DEQ for review and comment an Operations and Maintenance (O&M) manual that describes the procedures that will be followed to comply with General Provision 2 of this permit and the manufacturer specifications for the following control equipment:

- *Baghouses are used to control particulate emissions from rail unloading, handling, and storage of feedstocks. If bag leak detection systems are not provided, the O&M manual shall contain requirements for monthly see/no see visible emissions inspections of the baghouses. The inspections shall occur during daylight hours and under normal operating conditions. Visible emissions inspections for silo baghouses shall be conducted while material is being transferred at normal operating rates into the silo(s). If bag leak detection systems are used, the manual shall include appropriate provisions for inspection, maintenance, and testing of these systems.*
- *Fluxant water spray system(s) (if used), including alternative practices to be used during freezing condition*
- *Flue gas recirculation (FGR) system for reducing NO_X from the package boiler*
- *Selective catalytic reduction (SCR) system for reducing NO_X from the steam superheater boiler and the package boiler*
- *Oxidation catalyst (OxCat) for reducing CO emissions from the steam superheater boiler and the package boiler*
- *Sour water scrubber for removing trace metals and sulfides from the syngas*
- *Activated carbon beds for removing mercury from the syngas*
- *Amine scrubber used to decrease sulfur compounds in the syngas prior to flaring in the Gasifier Flare*
- *Flares, including the:*
  - *Gasifier flare*
  - *Process flare serving the ammonia and urea production plants*
  - *Ammonia storage flare*
- *Thermal oxidizer used to treat remaining H_2S, COS, and CO in the CO_2-rich stream from the AGR (AGR Stream 2)*
- *Extended absorption and SCR system(s) serving the nitric acid plant for the control of NO_X emissions*
- *Catalytic decomposition (or equivalent) for reducing N_2O emissions from the nitric acid plant*
- *Drift and mist eliminators and a condenser for the ammonium nitrate neutralizer vent*
- *Urea granulation process scrubber used to control PM/PM_{10} emissions*

As requested by the applicant, this permit condition has been revised to include the use of an oxidation catalyst control device for the control of CO emissions from the steam superheater and package boilers; to include the use of extended absorption in addition to SCR for the control of NO_X emissions from the nitric acid plant; to include the use of catalytic decomposition for the control of N_2O emissions from the nitric acid plant; and to include the use of drift and mist eliminators and a condenser for the control of particulate emissions from the ammonium nitrate neutralizer vent. A discussion of revisions related to SCR descriptions has been provided at the beginning of this section. Additional discussion for permit conditions revised based on the inclusion of this control equipment has also been provided below.

Initial Permit Condition 2.16

As requested by the applicant, these conditions permit the use of alternative feedstocks as a fraction of the feedstock to the gasifiers, in addition to coal, petcoke, and fluxant. A reasonable requirement has been included to ensure that alternative feedstocks do not contain hazardous waste. Recordkeeping of the results of sample analyses of each feedstock and relevant information has been required in Permit Condition 3.7 to ensure compliance with this restriction.

Alternative feedstocks were included in the proposed revisions to allow for the use of renewable resources, as fuel, to minimize emissions of CO_2. Alternative feedstocks will only be used during steady-state operations, and will not be used during startups. The use of alternative feedstocks is not expected to result in an emission increase as defined in IDAPA 58.01.01.007, and is not expected to result in the emission of any regulated air pollutant not previously emitted, from the two point sources downstream of the gasifier: the CO_2 Vent and the Steam Superheater, because the CO_2 Vent is the emission source for carbon dioxide, and it is equipped with a thermal oxidizer to oxidize carbon monoxide, hydrogen sulfide, and carbonyl sulfide. The steam superheater may burn PSA tailgas, which consists primarily of carbon monoxide, carbon dioxide, and hydrogen. A table listing the chemical composition of potential alternative feedstocks has been included in Appendix A, which demonstrates that for these materials, the sulfur content of the alternative feedstock is less than 6%, as required in Permit Condition 7.8.2.

Alternative feedstocks may be expected to include any of the materials listed in Appendix A. Because this list may not be exhaustive, and to allow the flexibility to include similar materials and categories of materials in alternative feedstocks, alternative feedstocks have not been defined within the permit. Subsequent permit conditions in Section 2 have been renumbered to reflect the additional permit condition.

Existing Permit Condition 2.16

The permittee may conduct source testing to evaluate changes to a process or control device including, but not limited to, a feed rate or production increase, change in feedstock parameters (e.g., sulfur content), or control device operational change, as follows:

- *Each source test shall be conducted in accordance with a DEQ-approved test protocol and in accordance with IDAPA 58.01.01.157.*
- *If the source test results demonstrate an exceedance of an existing emissions limit, and excess emissions report must be submitted to DEQ.*
- *After conducting the test, the source:*
  - *Shall return to compliance with existing permit restrictions until the appropriate permitting action is taken to change the operational restrictions, if the source test results demonstrate an exceedance of an existing emissions limit; or*
  - *May continue to operate at the new operational parameters achieved during the source test, if the source test results demonstrate compliance with applicable existing emission limits.*

Revised Permit Condition 2.17

The permittee may conduct source testing to evaluate changes to a process or control equipment including, but not limited to, a feed rate or production increase, change in feedstock parameters (e.g., sulfur content), or control equipment operational change, as follows:

- *Each source test shall be conducted in accordance with a DEQ-approved test protocol and in accordance with IDAPA 58.01.01.157.*
- *If the source test results demonstrate an exceedance of an existing emissions limit, an excess emissions report must be submitted to DEQ.*

- *The permittee shall monitor and record parameters relevant to the changes being evaluated and the parameters specified in Permit Condition 3.9.3.*
- *After conducting the test, the source:*
  - *Shall return to compliance with existing permit restrictions until the appropriate permitting action is taken to change the operational restrictions, if the source test results demonstrate an exceedance of an existing emissions limit; or*
  - *May continue to operate at the new operational parameters achieved during the source test, if the source test results demonstrate compliance with applicable existing emission limits.*
  - *Within 30 days following the date in which a performance test required by this permit is concluded, the permittee shall submit to DEQ a performance test report. The written report shall include a description of the process, identification of the test method(s) used, equipment used, all process operating data collected during the test period, and test results, as well as raw test data and associated documentation, including any approved test protocol.*

For clarification purposes, the requirement to submit a written report of any performance test result has been included within this permit condition. Submittal of the results of performance testing is generally required in accordance with General Provision 6. The reasonable requirement to monitor and record important process parameters during the performance test has also been added.

Existing Permit Condition 3.7

Prior to the initial startup that includes feeding slurry containing coal, petcoke, or fluxant to either gasifier, the permittee shall characterize the feedstocks by obtaining analysis results for representative composite samples from the feedstock supplier or shall sample and analyze the feedstocks to determine the concentration of the following toxics:

- *Metals in Coal/Petcoke/Fluxant: Arsenic, Cadmium, Chromium (total and hexavalent), Cobalt, Lead, Manganese, Mercury, and Nickel.*

Sampling and analysis shall be conducted in accordance with EPA Reference Methods or other method approved by DEQ.

The permittee shall obtain analysis results for the toxics listed in Permit Condition 3.7.1 for representative samples of feedstock prior to acceptance of coal, petcoke, or fluxant from a new mine or supplier.

The permittee shall obtain analysis results for the toxics listed in Permit Condition 3.7.1 for representative samples of feedstock at least every two years.

Records detailing the sampling method; sample identification; sampling date, time, and location; laboratory results; and any laboratory QA analysis shall be maintained in accordance with General Provision 7.

Revised Permit Condition 3.7

Prior to the initial startup that includes feeding slurry containing any blend of coal, petcoke, alternative feedstocks, and fluxant to either gasifier, the permittee shall characterize each feedstock by obtaining analysis results for representative composite samples from the feedstock supplier or shall sample and analyze each feedstock to determine the concentration of the following substances:

- *Sulfur content.*
- *Metals: Arsenic, Cadmium, Chromium (total and hexavalent), Cobalt, Lead, Manganese, Mercury, and Nickel.*
- *Any additional information necessary to ensure compliance with Permit Condition 2.16.*

Sampling and analysis shall be conducted in accordance with EPA Reference Methods or other method approved by DEQ.

The permittee shall obtain analysis results for the substances listed in Permit Condition 3.7.1 for representative samples of each feedstock prior to acceptance of coal, petcoke, alternative feedstocks, or fluxant from a mine or supplier.

The permittee shall obtain analysis results for the substances listed in Permit Condition 3.7.1 for representative samples of feedstock at least every two years.

Records of the information required by this permit condition and records detailing the sampling method; sample identification; sampling date, time, and location; laboratory results; and any laboratory QA analysis shall be maintained in accordance with General Provision 7.

As described in the discussion for initial Permit Condition 2.16 above, the applicant has requested the processing of alternative feedstocks in the gasifiers, in addition to coal, petcoke, and fluxant. Reasonable requirements to determine sulfur content and metal content have been included to ensure that the use of alternative feedstocks do not result in emissions greater than what was estimated in the emissions inventories submitted in the application for PTC No. P-2008.0066, and that the feedstocks do not contain hazardous waste as required in Permit Condition 2.16. Recordkeeping of the results of sample analyses of each feedstock is required to ensure compliance with these requirements.

Existing Permit Condition 6.2

The information contained in the table below summarizes the design basis upon which the permit has been issued. Minimum capture efficiencies for control equipment reflect approximate control levels.

Table 6.1 PACKAGE BOILER AND STEAM SUPERHEATER BOILER DESCRIPTION

Emissions Unit(s) / Process(es)	***Emissions Control Device***	***Emissions Point***
Package Boiler *Manufacturer/Model: TBD* *Max Rating: 250 MMBtu/hr heat input* *Heat Release Rate: (High or Low, TBD)* *Max. Operations: 8,760 hr/yr at full rating (combined with Steam Superheater Boiler hours)* *Fuel: Natural Gas Only* *Sulfur Content: 2.0 gr/100 dscf*	*Low-NO_X burner* *and* *Flue Gas Recirculation (FGR)* *Purpose: NO_X reduction* *Efficiency: 95% control for NO_X*	*Package Boiler Stack Parameters, SRC24:* *Stack Height: 33.5 m (110 ft)* *Exit Diameter: 1.8 m (5.9 ft)* *Orientation: vertical* *Exit flow rate: 52,282 acfm* *Exit Velocity: 10.3 m/sec* *Exit Temperature: 422 K (299.9^{o}F)*
Steam Superheater Boiler *Manufacturer/Model: TBD* *Max Rating: 250 MMBtu/hr heat input* *Heat Release Rate: (High or Low, TBD)* *Max. Operations: 8,760 hr/yr at full rating (combined with Package Boiler hours)* *Fuel: Natural Gas (max 250 MMBtu/hr)* *Heat Content: 1,020 Btu/scf* *Sulfur Content: 2.0 gr/100 dscf* *PSA Tailgas (max 250 MMBtu/hr)* *Heat Content: ~250 Btu/scf* *Sulfur Content: 25 ppmv*	*Low-NO_X burner* *and* *Selective Catalytic Reduction (SCR)* *Manufacturer/Model: TBD* *Purpose: NO_X reduction* *Efficiency: 97% control for NO_X* *Ammonia slip: $\leq$ 10 ppmv (dry), corrected to 15% O_2*	*Steam Superheater Stack Parameters, SRC31:* *Stack Height: 33.5 m (109.9 ft)* *Exit Diameter: 1.8 m (5.9 ft)* *Orientation: vertical* *Exit flow rate: 52,282 acfm* *Exit Velocity: 10.3 m/sec* *Exit Temperature: 422 K (299.9^{o}F)*

Revised Permit Condition 6.2

The information contained in the table below summarizes the design basis upon which the permit has been issued. Minimum capture efficiencies for control equipment reflect approximate control levels.

Table 6.1 STEAM SUPERHEATER BOILER AND PACKAGE BOILER DESCRIPTIONS

Emissions Unit(s) / Process(es)	***Emissions Control Device***	***Emissions Point***
Steam Superheater Boiler *Manufacturer/Model: TBD* *Max Rating: 250 MMBtu/hr heat input* *Heat Release Rate: (High or Low, TBD)* *Max. Operations: 8,760 hr/yr at full rating (combined with Package Boiler hours)* *Fuel: Natural Gas (max 250 MMBtu/hr)* *Heat Content: 1,020 Btu/scf* *Sulfur Content: 2.0 gr/100 dscf* *PSA Tailgas (max 250 MMBtu/hr)* *Heat Content: ~250 Btu/scf* *Sulfur Content: 25 ppmv*	*Low-NO_X burner* *and* *Selective Catalytic Reduction (SCR)* *Manufacturer/Model: TBD* *Purpose: NO_X reduction* *Efficiency: 97% control for NO_X* *Ammonia slip: $\leq$ 10 ppmv (dry), corrected to 15% O_2* *Oxidation Catalyst (OxCat)* *Manufacturer/Model: TBD* *Purpose: CO reduction* *Efficiency: 20 ppmv corrected to 3% O_2*	*Steam Superheater Stack Parameters, SRC31:* *Stack Height: 33.5 m (109.9 ft)* *Exit Diameter: 1.8 m (5.9 ft)* *Orientation: vertical* *Exit flow rate: 52,282 acfm* *Exit Velocity: 10.3 m/sec* *Exit Temperature: 422 K (299.9^{o}F)*
Package Boiler *Manufacturer/Model: TBD* *Max Rating: 250 MMBtu/hr heat input* *Heat Release Rate: (High or Low, TBD)* *Max. Operations: 8,760 hr/yr at full rating (combined with Steam Superheater Boiler hours)* *Fuel: Natural Gas Only* *Sulfur Content: 2.0 gr/100 dscf*	*Low-NO_X burner* *and* *Flue Gas Recirculation (FGR)* *Purpose: NO_X reduction* *Efficiency: 95% control for NO_X* *Oxidation Catalyst (OxCat)* *Manufacturer/Model: TBD* *Purpose: CO reduction* *Efficiency: 20 ppmv corrected to 3% O_2*	*Package Boiler Stack Parameters, SRC24:* *Stack Height: 33.5 m (110 ft)* *Exit Diameter: 1.8 m (5.9 ft)* *Orientation: vertical* *Exit flow rate: 52,282 acfm* *Exit Velocity: 10.3 m/sec* *Exit Temperature: 422 K (299.9^{o}F)*

As requested by the applicant, this permit condition has been revised to include an oxidation catalyst control device for the control of CO emissions from the steam superheater and package boilers. Refer to the additional discussion provided for Permit Conditions 6.3 and 6.11 for additional information.

Existing Permit Condition 6.3

The lb/MMBtu and pound per hour emission limits listed in Table 6.2 as BACT for CO, NO_x, PM, and PM_{10} for these sources, based on using low-NO_x burners for both the package boiler and steam superheater boiler, FGR to control NO_x emissions from the package boiler, and SCR with a maximum ammonia slip of 10 ppmv (dry) to control NO_x emissions from the steam superheater boiler.

The emissions from the package boiler and steam superheater boiler (affected facility) shall not exceed any corresponding emissions rate limits listed in Table 6.2.

Table 6.2 PACKAGE BOILER AND STEAM SUPERHEATER BOILER EMISSIONS LIMITS [1]

Source	*PM*		*PM_{10}[2]*		*SO_2*		*NO_X*		*VOC*		*CO*	
Description	*lb/hr[3]*	*T/yr[4]*	*lb/hr[3]*	*T/yr[4]*	*lb/hr[3]*	*T/yr[4]*	*lb/hr[3]*	*T/yr[4]*	*lb/hr*	*T/yr[4]*	*lb/hr[3]*	*T/yr[4]*
BACT Limit: *250 MMBtu/hr Package Boiler and 250 MMBtu/hr Steam Superheater, combined*	*0.0052 lb/ MMBtu*	---	*0.0052 lb/ MMBtu*	---	---	---	*0.02 lb/ MMBtu*	---	---	---	*0.074 lb/ MMBtu*	---
Secondary Limits: *250 MMBtu/hr Package Boiler and 250 MMBtu/hr Steam Superheater, combined*	*1.3*	*5.7*	*1.3*	*5.7*	*1.4*	*6.3*	*5.0*	*21.9*	*1.0*	*4.4*	*18.5*	*81.0*

1) *In the absence of any other creditable evidence, compliance is assured by complying with this permit's operating, monitoring and record keeping requirements.*
2) *Particulate matter with and aerodynamic diameter less than or equal to a nominal ten (10) micrometers including condensable particulate as defined in IDAPA 58.01.01.006.81.*
3) *As determined by source test methods prescribed by IDAPA 58.01.01.157.*
4) *Tons per any consecutive 12-calendar month period.*

Revised Permit Condition 6.3

The emissions from the steam superheater boiler and the package boiler (affected facility) shall not exceed any corresponding emissions rate limits listed in Table 6.2.

Table 6.2 STEAM SUPERHEATER BOILER AND PACKAGE BOILER EMISSIONS LIMITS[1]

Source Description	PM		PM_{10}[2]		SO_2		NO_X		VOC		CO	
	lb/hr[3]	T/yr[4]	lb/hr[3]	T/yr[4]	lb/hr[3]	T/yr[4]	lb/hr[3]	T/yr[4]	lb/hr	T/yr[4]	lb/hr[3]	T/yr[4]
BACT Limit: 250 MMBtu/hr Package Boiler and 250 MMBtu/hr Steam Superheater, combined	*0.0052 lb/ MMBtu*	---	*0.0052 lb/ MMBtu*	---	---	---	*0.006 lb/ MMBtu*	---	---	---	*0.015 lb/ MMBtu*	---
Secondary Limits: 250 MMBtu/hr Package Boiler and 250 MMBtu/hr Steam Superheater, combined	*1.3*	*5.7*	*1.3*	*5.7*	*1.4*	*6.3*	*1.5*	*6.6*	*1.0*	*4.4*	*3.8*	*16.5*

1) *In the absence of any other credible evidence, compliance is assured by complying with this permit's operating, monitoring and record keeping requirements.*
2) *Particulate matter with and aerodynamic diameter less than or equal to a nominal ten (10) micrometers including condensable particulate as defined in IDAPA 58.01.01.006.81.*
3) *As determined by source test methods prescribed by IDAPA 58.01.01.157.*
4) *Tons per any consecutive 12-calendar month period.*

The lb/MMBtu and pounds per hour respective NO_X, PM, and PM_{10} emissions limits in Table 6.2 are BACT emissions limits for the control of NO_X, PM, and PM_{10} emissions from the steam superheater boiler and the package boiler, based on the use of the control equipment specified in Permit Condition 6.10.

BACT emissions limits for the control of CO emissions from the steam superheater boiler and the package boiler are 0.074 lb/MMBtu and 18.5 lb/hr, based on the use of good combustion practices.

The lb/MMBtu and pounds per hour respective CO emissions limits in Table 6.2 are based on the use of the control equipment specified in Permit Condition 6.11 for the control of CO emissions from the steam superheater boiler and the package boiler. Compliance with the CO emissions limits in Table 6.2 shall be deemed compliance with the BACT emissions limits in Permit Condition 6.3.3.

As requested by the applicant, the NO_X emissions limits for the boilers have been reduced. The revised BACT limit and secondary limits for NO_X emissions have been limited in lb/MMBtu, lb/hr, and T/yr for the sake of consistency. The annual limits (T/yr) for the boilers inherently limit the total amount of natural gas and PSA tailgas that can be combusted within the boilers. Refer to the statement of basis for PTC No. P-2008.0066 for additional information.

As requested by the applicant, the CO emissions of the boilers have been limited based on the installation, operation, and maintenance of an oxidation catalyst (OxCat).

In the initial permit to construct (PTC No. P-2008.0066), it was determined that BACT for the control of NO_X emissions from the steam superheater and the package boiler was SCR. Emission limits were based on multiple fuels: natural gas, PSA tailgas, and a blend of natural gas and PSA tailgas. The use of PSA tailgas has a significant impact on NO_X emissions because it contains a high concentration of hydrogen. The limit for NO_X was established assuming 100% tailgas.

The permittee has since reengaged boiler technology providers to reconsider NO_X emissions from the steam superheater and package boiler. The permittee provided the boiler technology providers with an estimate of the chemical composition of the PSA tailgas, which was derived from internal chemical process modeling. Based on this revised and more detailed information, the boiler technology providers were able to provide a better estimate of their emissions guarantee for SCR, which reflects a NO_X emission rate of 5 ppm.

In the initial permit to construct (PTC No. P-2008.0066) it was determined that BACT for the control of CO emissions from the steam superheater and the package boiler was good combustion practices. The permittee had evaluated the incremental cost effectiveness of OxCat compared to using good combustion practices, and had demonstrated that OxCat could be ruled out on an economic basis. The permittee maintains and DEQ has determined that OxCat exceeds what would typically be required as CO BACT for small boilers. Despite the prohibitive cost, the permittee has agreed to install and operate OxCat for the control of CO emissions from the steam superheater and package boilers.

The permittee has requested more stringent, enforceable emissions limits based on the installation and operation of OxCat on both the Steam Superheater and Package Boilers.

Initial Permit Condition 6.11

As requested by the applicant, this permit condition requires the installation, maintenance, and operation of an oxidation catalyst necessary to comply with the CO emissions limits in Permit Condition 6.3. Refer to discussion provided for Permit Condition 6.3 above for additional information.

Subsequent permit conditions in Section 6 have been renumbered to reflect the additional permit condition.

Initial Permit Condition 6.16

As requested by the applicant, this permit condition requires CO emissions monitoring with the use of a CEMS or PEMS and recordkeeping to demonstrate compliance with the revised CO emissions limits in Permit Condition 6.3.

Subsequent permit conditions in Section 6 have been renumbered to reflect the additional permit condition.

Initial Permit Condition 6.23

As requested by the applicant, this permit condition requires reporting of CO emissions records to ensure compliance with the revised CO emissions limits in Permit Condition 6.3.

Subsequent permit conditions in Section 6 have been renumbered to reflect the additional permit condition.

Revised Permit Condition 7.1

As requested by the applicant, information concerning startups and upsets in the process description has been revised to include the option of using sulfur-free fuels in the gasifier in order to minimize emissions during startups. Refer to the additional discussion provided below for Permit Condition 7.8.

Revised Permit Condition 7.2

As requested by the applicant, information concerning the control of fugitive CO emissions in the process description has been revised to include the use of BMP. Additional information concerning fugitive BMP plan requirements has been provided in the discussion for revised Permit Condition 7.13. A discussion of revisions related to feedstock descriptions has been provided at the beginning of this section.

Initial Permit Conditions 7.3, 7.5, 7.6, 7.7, 7.15, 7.16, 7.17, 7.18, and 7.19

As requested by the applicant, these permit conditions include an emissions limit and supporting requirements concerning CO_2 emissions from the AGR Stream 2: CO_2 Vent.

It should be noted that EPA does not currently consider CO_2 to be a “regulated NSR pollutant” as defined in 40 CFR 52.21(b)(50), and that DEQ does not currently consider CO_2 to be a regulated air pollutant (IDAPA 58.01.01.006.95) or a state-only toxic air pollutant (IDAPA 58.01.01.006.120). At the request of the applicant, DEQ has included a CO_2 emissions limit and supporting requirements for the control of an unregulated air contaminant.

- Permit Condition 7.3 defines the terms associated with the CO_2 emissions limits and supporting requirements.

- Permit Condition 7.5 limits annual emissions of CO_2 from the AGR Stream 2: CO_2 Vent.
- Permit Condition 7.6 specifies that the effective date of the CO_2 emissions limits is the fifth anniversary after mechanical completion of the facility.
- Permit Condition 7.7 requires federal, state, or regional greenhouse gas offsets to be purchased annually if the permittee is not otherwise in compliance with the CO_2 emissions limit.
- Permit Condition 7.15 requires monitoring and reporting requirements to demonstrate compliance with the CO_2 emissions limit, which may include the use of a flow rate CMS. This permit condition also specifies requirements for substitution and treatment of missing data based in part on the requirements of 40 CFR Part 75 (Continuous Emission Monitoring).
- Permit Condition 7.16 requires semi-annual recordkeeping and reporting to demonstrate compliance with Measurement, Monitoring, and Verification Plans associated with CO_2 emissions limits.
- Permit Condition 7.17 specifies that the facility shall comply with applicable federal and state greenhouse gas emissions reporting requirements if applicable, or shall submit monthly reports of annual CO_2 emissions from the AGR Stream 2: CO_2 Vent based on flow rate CMS data.
- Permit Conditions 7.18 and 7.19 require reporting to ensure compliance with Permit Conditions 7.7 and 7.6, respectively.

The permittee, in cooperation with the Sierra Club and the Idaho Conservation League, petitioned DEQ to include a CO_2 emissions limit for CO_2 emissions originating from the AGR Stream 2: CO_2 Vent point source. The permittee accepted this CO_2 emissions limit and has requested to make it an enforceable provision. Documentation of the agreement between the permittee and the Sierra Club and the Idaho Conservation League has been included in Appendix B.

Subsequent permit conditions in Section 7 have been renumbered to reflect the additional permit conditions.

Existing Permit Condition 7.4

The CO, NO_x, and SO_2 emissions from the AGR CO_2 vent stack shall not exceed any corresponding emissions rate limits listed in that table. The pound per hour CO and NO_x limits are BACT limits.

Table 7.2 GASIFICATION ISLAND EMISSIONS LIMITS[1]

Source Description	*PM*		*PM_{10}*[2]		*SO_2*		*NO_X*		*VOC*		*CO*	
	lb/hr	*T/yr*[4]	*lb/hr*	*T/yr*[4]	*lb/hr*	*T/yr*[4]	*lb/hr*[3]	*T/yr*[4]	*lb/hr*	*T/yr*[4]	*lb/hr*[3]	*T/yr*[4]
Selexol AGR Stream 2: CO_2 Vent	---	---	---	---	*3.8*	*16.5*	*0.9*	*3.9*	---	---	*8.7*	*38.0*

1) *In the absence of any other creditable evidence, compliance is assured by complying with this permit's operating, monitoring and record keeping requirements.*
2) *Particulate matter with and aerodynamic diameter less than or equal to a nominal ten (10) micrometers including condensable particulate as defined in IDAPA 58.01.01.006.81.*
3) *As determined by source test methods prescribed by IDAPA 58.01.01.157.*
4) *Tons per any consecutive 12-calendar month period.*

Revised Permit Condition 7.4

The CO, NO_X, and SO_2 emissions from the AGR Stream 2: CO_2 Vent stack and fugitive emissions shall not exceed any corresponding emissions rate limits listed in Table 7.2. The pounds per hour CO and NO_X emissions limits are BACT limits.

Table 7.2 GASIFICATION ISLAND CRITERIA POLLUTANT EMISSIONS LIMITS[1]

Source Descriptions	*PM*		*PM_{10}*[2]		*SO_2*		*NO_X*		*VOC*		*CO*	
	lb/hr	*T/yr*[4]	*lb/hr*	*T/yr*[4]	*lb/hr*	*T/yr*[4]	*lb/hr*[3]	*T/yr*[4]	*lb/hr*	*T/yr*[4]	*lb/hr*[3]	*T/yr*[4]
AGR Stream 2: CO_2 Vent	---	---	---	---	*3.8*	*16.5*	*0.9*	*3.9*	---	---	*8.7*	*38.0*
Fugitive emissions[5]	---	---	---	---	---	---	---	---	---	---	---	*31*

1) *In the absence of any other credible evidence, compliance is assured by complying with this permit's operating, monitoring and record keeping requirements.*
2) *Particulate matter with and aerodynamic diameter less than or equal to a nominal ten (10) micrometers including condensable particulate as defined in IDAPA 58.01.01.006.81.*
3) *As determined by source test methods prescribed by IDAPA 58.01.01.157.*
4) *Tons per any consecutive 12-calendar month period.*
5) *Defined as fugitive emissions between the outlet of the gasifier/quench vessel and the outlet of the final CO-shift reactor. Compliance to be demonstrated by implementing the Fugitive CO Best Management Practices Plan as required in Permit Condition 7.13.*

As requested by the applicant, this permit condition has been revised to include CO fugitive emissions limits.

The applicant has requested an annual fugitive CO emissions limit and further definition of the Fugitive CO BMP Plan in order to demonstrate compliance with this limit. Fugitive emissions of CO associated with gasification include emissions from component leaks between the gasifier outlet and the final shift reactor outlet. In the initial permit to construct application, fugitive emissions were estimated at approximately 31 T/yr. Refer to Appendix D of the application for PTC No. P-2008.0066 for additional information.

The work practices required by the Fugitive CO BMP Plan were determined to be BACT in PTC No. P-2008.0066 for minimizing fugitive CO emissions. The applicant has requested that a fugitive CO emissions limit and additional work practice requirements be included as BACT limits for the control of fugitive CO emissions.

Existing Permit Condition 7.4

The permittee shall install, calibrate, and operate a means to monitor and record the weight of the coal, petcoke, and fluxant fed to the gasifier, individually and combined, in tons per day.

Solid feedstock to the gasifiers shall not contain more than:

- *6.0% sulfur by weight as blended, based on the as-received sulfur content of the coal, petcoke, and fluxant,*

  or

- *The sulfur content of the solid feedstock blend used to produce the syngas for any performance test conducted within the previous five year period that demonstrated compliance with applicable SO_2 emission limits for the wet sulfuric acid plant (if installed), and the SO_2 emissions from the gasifier flare when burning syngas and for worst-case normal operating conditions.*

The sulfur content of the solid feedstock shall be calculated based on the as-received sulfur content of the coal, petcoke, and fluxant.

The amount of coal and petcoke fed to the gasifiers shall not exceed 5,000 tons per day of blended coal and petcoke and 250 tons per day of fluxant.

The operating level of the gasifier(s) shall not at any time exceed the actual working capacity of the syngas cleanup train.

Revised Permit Condition 7.8

The permittee shall install, calibrate, and operate a means to monitor and record the weight of the coal, petcoke, alternative feedstocks, and fluxant fed to the gasifier, individually and combined, in tons per day.

Solid feedstock to the gasifiers shall not contain more than:

- *6.0% sulfur by weight as blended, based on the as-received sulfur content of the coal, petcoke, alternative feedstocks, and fluxant,*

  or

- *The sulfur content of the solid feedstock blend used to produce the syngas for any performance test conducted within the previous five year period that demonstrated compliance with applicable SO_2 emission limits for the wet sulfuric acid plant (if installed), and the SO_2 emissions from the gasifier flare when burning syngas and for worst-case normal operating conditions.*

The sulfur content of the solid feedstock shall be calculated based on the as-received sulfur content of the coal, petcoke, alternative feedstocks, and fluxant.

The amount of coal, petcoke, and alternative feedstocks fed to the gasifiers shall not exceed 5,000 tons per day of blended coal, petcoke, and alternative feedstocks; and 250 tons per day of fluxant.

The operating level of the gasifier(s) shall not at any time exceed the actual working capacity of the syngas cleanup train.

Planned startups of the gasifier that use coal and petcoke as fuel shall be limited to 13 events in any rolling 12-month period.

Planned startups of the gasifier that use sulfur-free alcohol-based fuels, including methanol, shall not count toward the limit of 13 events in Permit Condition 7.8.6.

As requested by the applicant, this permit condition has been revised to include limits on the number of gasifier startups using petcoke and coal, and to include the alternative to use sulfur-free alcohol-based fuels and alternative feedstocks. A discussion of revisions related to feedstock descriptions has been provided at the beginning of this section.

Startups of the gasifier on coal and/or petcoke have the potential to release approximately 0.5 tons of SO_2 per startup. These emissions were estimated and characterized in Appendix D of the application for PTC No. P-2008.0066 (steady-state emissions of SO_2 were estimated to be approximately 32.3 T/yr, and each gasifier startup was estimated to emit an additional 0.5 T/yr SO_2). It was conservatively estimated that the PCAEC will experience approximately 50 startups per year. Certain technology providers offer a startup technology that uses a sulfur-free fuel (generally an alcohol like methanol). Startups using a sulfur-free fuel significantly reduce emissions of SO_2 without increasing emissions of other criteria air pollutants, hazardous air pollutants, and toxic air pollutants. The sulfur-free fuel does not contain mercury and sulfur, and therefore, it is not necessary to route the syngas generated during these startups through the activated carbon beds or the amine scrubber for emissions control. During startup using this fuel, the syngas will still be routed to the flare, which has in excess of 98% destruction efficiency for VOC, CO, NH_3, and H_2S. The permittee will have a reliable startup technology using sulfur-free alcohol-based fuels such as methanol, for any remaining startups in excess of the 13 startups using coal and/or petcoke.

The applicant has requested an operating restriction when starting on coal or petcoke that may limit actual SO_2 emissions to a level below 40 T/yr (no offsetting or netting of emissions reductions has been requested, as discussed in the emissions inventories and ambient air impact analyses section above). Startups using a sulfur-free alcohol-based fuel are not expected to result in an emission increase as defined in IDAPA 58.01.01.007, and are not expected to result in the emission of any regulated air pollutant not previously emitted.

Existing Permit Condition 7.7

The permittee shall monitor and record:

- *The amount of coal, petcoke, and fluxant fed to the gasifiers, in tons per day.*
- *The sulfur content of the feedstock blend fed to the gasifiers, in percent by weight. The sulfur content of the feedstock blend shall be calculated based on the as-received sulfur content and amount fed that day for each of the feedstocks.*

- *Records of this information shall be maintained in accordance with General Provision 7.*

Revised Permit Condition 7.11

The permittee shall monitor and record the following information, on a daily basis:

- *Each amount of coal, petcoke, alternative feedstocks, and fluxant fed to the gasifiers, in tons per day.*
- *The total amount of coal, petcoke, alternative feedstocks, and fluxant fed to the gasifiers, in tons per day.*
- *The sulfur content of the feedstock blend fed to the gasifiers, in percent by weight. The sulfur content of the feedstock blend shall be calculated based on the as-received sulfur content and amount fed that day for each of the feedstocks.*
- *Records of this information shall be maintained in accordance with General Provision 7.*

Variability in the type and amounts of materials used as alternative feedstocks is expected and implicit to the use of renewable resources as substitute feedstocks. A reasonable permit condition has been included to track the amount of each alternative feedstock used in addition to the overall throughput on a daily basis to ensure compliance with annual throughput and CO_2 offset limits.

Existing Permit Condition 7.10

At least 60 days before initial startup of the gasifiers, the permittee shall have developed and submitted to DEQ for review and comment a best management practices (BMP) plan designed to reduce fugitive emissions of CO. The Fugitive CO BMP plan shall include the following, as a minimum:

- *Identify each equipment component potentially subject to fugitive CO emissions that is located between the outlet of the gasifier/quench vessel and the outlet of the final CO-shift reactor.*
- *Provide a means to physically identify each of these components in the plant. Physically tagging each component is not required if the equipment is clearly identified on current as-built piping and instrumentation diagrams (P&IDs) or other design drawings.*
- *Define observed parameter(s) that constitute a leak from each equipment component (e.g., visible liquid, misting, or clouding; a sound such as hissing; a smell; or measured CO level in ppm).*
- *The scheduled frequency for routine inspections.*
- *Requirements for attempting repairs as soon as practicable after a leak is detected. Repair attempts should include, but not be limited to, tightening or replacing bonnet bolts, tightening packing gland nuts, and injecting lubricant into lubricated packing.*
- *If the repair of any component is technically infeasible without a process shutdown, provide a means for documenting the needed repair, the reason that the repair must be delayed, for scheduling the repair for the next available planned shutdown, and for closing out the repair item.*
- *A schedule for post-repair monitoring and inspection to ensure that a "leak" as defined in the Fugitive CO BMP Plan is no longer occurring.*
- *Recordkeeping requirements including, but not limited to, equipment components subject to fugitive CO monitoring; inspection and repair records that include the date, time, identity of the inspector, leak detection method used, inspection results, repair(s) attempted, and the date and nature of repair(s).*

These records shall be maintained in accordance with General Provision 7.

The permittee shall maintain and implement the Fugitive CO BMP Plan.

The work practices described in the Fugitive CO BMP Plan constitute BACT for controlling fugitive CO emissions.

Revised Permit Condition 7.13

At least 60 days before initial startup of the gasifiers, the permittee shall have developed and submitted to DEQ for review and comment a best management practices (BMP) plan designed to quantify and reduce fugitive emissions of CO. The Fugitive CO BMP plan shall include the following, at a minimum:

- *Identify each equipment component potentially subject to fugitive CO emissions that is located between the outlet of the gasifier/quench vessel and the outlet of the final CO-shift reactor.*
- *Develop methodologies to quantify annual fugitive emissions of CO necessary to demonstrate compliance with the fugitive emissions limit in Table 7.2 of Permit Condition 7.4.*
- *Provide a means to physically identify each of these components in the plant. Physically tagging each component is not required if the equipment is clearly identified on current as-built piping and instrumentation diagrams (P&ID) or other design drawings.*
- *Define observed parameter(s) that constitute a leak from each equipment component (e.g., visible liquid, misting, or clouding; a sound such as hissing; a smell; or measured CO level in ppm).*
- *The scheduled frequency for routine inspections.*
- *Requirements for attempting repairs as soon as practicable after a leak is detected. Repair attempts should include, but not be limited to, tightening or replacing bonnet bolts, tightening packing gland nuts, and injecting lubricant into lubricated packing.*
- *If the repair of any component is technically infeasible without a process shutdown, provide a means for documenting the needed repair, the reason that the repair must be delayed, for scheduling the repair for the next available planned shutdown, and for closing out the repair item.*
- *A schedule for post-repair monitoring and inspection to ensure that a "leak" as defined in the Fugitive CO BMP Plan is no longer occurring.*
- *Recordkeeping requirements including, but not limited to, equipment components subject to fugitive CO monitoring; inspection and repair records that include the date, time, identity of the inspector, leak detection method used, inspection results, repair(s) attempted, and the date and nature of repair(s).*

These records shall be maintained in accordance with General Provision 7.

The permittee shall maintain and implement the Fugitive CO BMP Plan.

The work practices described in the Fugitive CO BMP Plan constitute BACT for controlling fugitive CO emissions.

As requested by the applicant, this permit condition has been revised to include the requirement to quantify annual fugitive CO emissions to demonstrate compliance with the CO fugitive emissions limit. Refer to the additional discussion provided above for revised Permit Condition 7.4.

Revised Permit Condition 8.2

As requested by the applicant, information concerning the urea plant control equipment description has been revised to include the use of drift and mist eliminators for the control of particulate emissions from the wet scrubber.

Revised Permit Condition 9.2

As requested by the applicant, information concerning the nitric acid plant and ammonium nitrate/UAN plant control equipment descriptions has been revised. The nitric acid plant control equipment description has been revised to include the use of extended absorption and SCR for the control of NO_X emissions (with a control efficiency of 90% to achieve the limit of 0.60 lb/ton discussed in revised Permit Condition 9.3 below), and catalytic decomposition for the control of N_2O emissions. The ammonium nitrate/UAN plant control equipment description has been revised to include the use of drift and mist eliminators and a condenser for the control of particulate emissions.

Existing Permit Condition 9.3

The PM, PM_{10}, and NO_X emissions from the nitric acid tailgas stack and the ammonium nitrate neutralizer vent shall not exceed any corresponding emissions rate limits listed in Table 9.2.

Table 9.2 NITRIC ACID AND AMMONIUM NITRATE/UAN PLANTS EMISSIONS LIMITS[1]

Source Description	PM		PM_{10}		SO_2		NO_X		VOC		CO	
	lb/hr[3]	T/yr[4]	lb/hr[3]	T/yr[4]	lb/hr	T/yr	As noted[3]	T/yr[4]	lb/hr	T/yr[4]	lb/hr	T/yr[4]
BACT Limits: Nitric Acid Tailgas Vent	---	---	---	---	---	---	50 ppmv	---	---	---	---	---
Secondary Limits: Nitric Acid Tailgas Vent	---	---	---	---	---	---	15.3 lb/hr	67.2	---	---	---	---
AN Neutralizer Vent	1.5	---	1.5	6.5	---	---	---	---	---	---	---	---

1) *In the absence of any other creditable evidence, compliance is assured by complying with this permit's operating, monitoring and record keeping requirements.*
2) *Particulate matter with and aerodynamic diameter less than or equal to a nominal ten (10) micrometers including condensable particulate as defined in IDAPA 58.01.01.006.81.*
3) *As determined by source test methods prescribed by IDAPA 58.01.01.157.*
4) *Tons per any consecutive 12-calendar month period.*

Revised Permit Condition 9.3

The PM, PM_{10}, and NO_X emissions from the nitric acid tailgas stack and the ammonium nitrate neutralizer vent shall not exceed any corresponding emissions rate limits listed in Table 9.2.

Table 9.2 NITRIC ACID PLANT AND AMMONIUM NITRATE/UAN PLANT EMISSIONS LIMITS[1]

Source Description	PM		PM_{10}		SO_2		NO_X		VOC		CO		N_2O
	lb/hr[3]	T/yr[4]	lb/hr[3]	T/yr[4]	lb/hr	T/yr	As noted[3]	T/yr[4]	lb/hr	T/yr[4]	lb/hr	T/yr[4]	ppmv
BACT Limits: Nitric Acid Tailgas Vent	---	---	---	---	---	---	50 ppmv and 0.6 lb/ton[5]	---	---	---	---	---	---
Secondary Limits: Nitric Acid Tailgas Vent	---	---	---	---	---	---	14.4 lb/hr	63.0	---	---	---	---	---
Catalytic Decomposition system	---	---	---	---	---	---	---	---	---	---	---	---	300
AN Neutralizer Vent	1.5	---	1.5	6.5	---	---	---	---	---	---	---	---	---

1) *In the absence of any other credible evidence, compliance is assured by complying with this permit's operating, monitoring and record keeping requirements.*
2) *Particulate matter with and aerodynamic diameter less than or equal to a nominal ten (10) micrometers including condensable particulate as defined in IDAPA 58.01.01.006.81.*
3) *As determined by source test methods prescribed by IDAPA 58.01.01.157.*
4) *Tons per any consecutive 12-calendar month period.*
5) *Emission rate based on a BACT Limit of 0.6 lbs of NO_X per ton of pure acid.*

As requested by the applicant, this permit condition has been revised to include reduced limits for NO_X emissions from the nitric acid plant, and a N_2O emissions limit from the catalytic decomposition system.

The BACT limit for NO_X emissions was limited in ppmv in PTC No. P-2008.0066. Based on additional information provided, it has been determined that an emissions limit of 0.60 lb/ton can be achieved based on the selected best available control technology, and this limit has also been included as a BACT emissions limit. Similarly, the secondary limits in pounds per hour and tons per year have also been revised.

The applicant has reengaged the technology provider to reconsider the emissions guarantees previously submitted. Based on volumetric flow rates from two technology providers, the 50 ppmv (dry) limit would result in an emission rate that varies between 0.60 and 0.65 pounds of NO_X per ton of pure nitric acid. The technology provider selected has provided a guarantee that an emissions rate of 0.60 lb/ton can be achieved through the use of extended absorption and SCR.

Existing Permit Condition 9.5

The permittee shall install, maintain, and operate a selective catalytic reduction (SCR) system to control NO_X emissions from the nitric acid production unit tailgas.

The NO_X SCR system shall be operated at all times when the nitric acid production unit is being operated.

The ammonia slip for the SCR system shall not exceed 10 ppmv (dry) converted to 15% oxygen.

The scrubber that is integral to the ammonium nitrate neutralizer process (process equipment) must be designed to capture and recycle a minimum of 90% of the PM/PM_{10} within the process.

Revised Permit Condition 9.5
The permittee shall install, maintain, and operate an extended absorption system and a selective catalytic reduction (SCR) system to control NO_x emissions from the nitric acid production unit tailgas.

The extended absorption system and NO_x SCR system shall be operated at all times when the nitric acid production unit is being operated.

The ammonia slip for the SCR system shall not exceed 10 ppmv (dry) converted to 15% oxygen.

The Catalytic Decomposition system (or equivalent) shall be operated at all times when the nitric acid production unit is being operated to achieve an N_2O emission rate of 300 ppmv or less.

The scrubber that is integral to the ammonium nitrate neutralizer process (process equipment) must be designed to capture and recycle a minimum of 90% of the PM/PM_{10} within the process.

As requested by the applicant, this permit condition has been revised to include the use of extended absorption in addition to SCR for the control of NO_X emissions from the nitric acid plant; and to include the use of catalytic decomposition for the control of N_2O emissions from the nitric acid plant.

As part of the demonstration of preconstruction compliance with toxic standards, specifically for the non-carcinogenic increment for nitrous oxide (N_2O), the applicant provided information[3] that N_2O emissions from the Nitric Acid Plant could be controlled through catalytic decomposition to a concentration of 300 ppmv, based on information from technology providers. The applicant has requested that N_2O emissions be limited to 300 ppmv, and the technology provider has provided a guarantee of performance at this level.

Initial Permit Condition 9.9

As requested by the applicant, this permit condition requires a performance test to measure total PM concurrently with the initial performance test (required by Permit Condition 9.8) to demonstrate compliance with the PM emissions limit in Permit Condition 9.3.

Subsequent permit conditions in Section 9 have been renumbered to reflect the additional permit condition.

[3] "Trinity and SIE's Response to IDEQ Request for Additional Information Dated 12/24/2008", memorandum submitted to DEQ January 9, 2009.

Permit Processing Fee

The processing fee associated with this permitting action is determined based on the total annual emissions change, in accordance with IDAPA 58.01.01.225. Because this permitting action involves no emissions increase, and because this PTC is a modification where additional engineering analysis was not required, the facility is subject to a processing fee of $250. Refer to the chronology for fee receipt dates.

Public Comment Opportunity

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

APPENDIX A – MATERIALS IN ALTERNATIVE FEEDSTOCKS

Chemical Composition of Typical Alternative Feedstocks

Name	Fixed	Volatiles	Ash	C	H	O	N	**S**	HHV	HHV
	Carbon								MEAS	CALC
	%	%	%	%	%	%	%	**%**	kJ/g	kJ/g
WOOD										
Beech	-	-	0.65	51 64	6 26	41.45	0	**0**	20.38	21.1
Black Locust	18.26	80.94	0.8	50.73	5.71	41.93	0.57	**0.01**	19.71	20.12
Douglas Fir	17.7	81.5	0.8	52.3	6.3	40.5	0.1	**0**	21.05	21.48
Hickory	-	-	0.73	47 67	6.49	43.11	0	**0**	20.17	19.82
Maple	-	-	1.35	50 64	6 02	41.74	0.25	**0**	19.96	20.42
Ponderosa Pine	17.17	82.54	0.29	49 25	5 99	44.36	0.06	**0.03**	20.02	19.66
Poplar	-	-	0.65	51 64	6 26	41.45	0	**0**	20.75	21.1
Red Alder	12 5	87.1	0.4	49 55	6 06	43.78	0.13	**0.07**	19 3	19.91
Redwood	16.1	83 5	0.4	53.5	5.9	40.3	0.1	**0**	21.03	21.45
Western Hemlock	15 2	84 8	2.2	50.4	5.8	41.1	0.1	**0.1**	20.05	20.14
Yellow Pine	-	-	1.31	52.6	7	40.1	0	**0**	22 3	22.44
White Fir	16.58	83.17	0.25	49	5 98	44.75	0.05	**0.01**	19.95	19.52
White Oak	17 2	81.28	1.52	49.48	5 38	43.13	0.35	**0.01**	19.42	19.12
Madrone	12	87 8	0.2	48 94	6 03	44.75	0.05	**0.02**	19.51	19.56
Mango Wood	11.36	85.64	2.98	46 24	6 08	44.42	0.28		19.17	18.65
BARK										
Douglas Fir bark	25 8	73	1.2	56.2	5.9	36.7	0	**0**	22.1	22.75
Loblolly Pine bark	33 9	54.7	0.4	56.3	5.6	37.7	0	**0**	21.78	22.35
ENERGY CROPS										
Eucalyptus Camaldulensis	17.82	81.42	0.76	49	5 87	43.97	0.3	**0.01**	19.42	19.46
Casuarina	19.58	78.58	1.83	48.5	6 04	43.32	0.31	**0**	18.77	19.53
Poplar	16.35	82.32	1.33	48.45	5 85	43.69	0.47	**0.01**	19.38	19.26
Sudan Grass	18 6	72.75	8.65	44 58	5 35	39.18	1.21	**0.01**	17.39	17.62
PROCESSED BIOMASS										
Plywood	15.77	82.14	2.09	48.13	5 87	42.46	1.45	**0**	18.96	19.26
AGRICULTURAL										
Peach Pits	19.85	79.12	1.03	53	5.9	39.14	0.32	**0.05**	20.82	21.39
Walnut Shells	21.16	78.28	0.56	49 98	5.71	43.35	0.21	**0.01**	20.18	19.68
Almond Prunings	21.54	76.83	1.63	51.3	5 29	40.9	0.66	**0.01**	20.01	19.87
Black Walnut Prunings	18.56	80.69	0.78	49.8	5 82	43.25	0.22	**0.01**	19.83	19.75
Corncobs	18.54	80.1	1.36	46 58	5 87	45.46	0.47	**0.01**	18.77	18.44
Wheat Straw	19 8	71 3	8.9	43.2	5	39.4	0.61	**0.11**	17.51	16.71
Cotton Stalk	22.43	70.89	6.68	43 64	5 81	43 87	0	**0**	18.26	17.4
Corn Stover	19.25	75.17	5.58	43 65	5 56	43 31	0.61	**0.01**	17.65	17.19
Sugarcane Bagasse	14.95	73.78	11.27	44.8	5 35	39 55	0.38	**0.01**	17.33	17.61
Rice Hulls	15 8	63.6	20.6	38.3	4 36	35.45	0.83	**0.06**	14.89	14.4
Pine needles	26.12	72.38	1.5	48 21	6 57	43.72			20.12	20.02
Cotton gin trash	15.1	67.3	17.6	39 59	5 26	36.38	2.09	**0**	16.42	15.85
AQUATIC BIOMASS										
Water Hyacinth (Florida)	-	80.4	19.6	40.3	4.6	33.99	1.51	**0**	14.86	15.54
Brown Kelp,Giant, Soquel Point	-	57.9	42.1	27.8	3.77	23.69	4.63	**1.05**	10.75	10.85
AVERAGE				47 91	5.74	40.98	0.52	**0.05**	19.11	19.15
LIQUID FUELS										
Methanol, CH3OH	0		0	37.5	12.5	50	0	**0**	22.69	22.65
Ethanol, C2H5OH	0		0	52.2	13	34.8	0	**0**	30.15	29.94
PYROLYSIS OILS										
LBL Wood Oil			0.78	72.3	8.6	17.6	0.2	**0.01**	33.7	33.53
BOM wood oil			0.66	82	8.8	9.2	0.6	**0**	36 8	38.02
Coke-oven tar			0.25	91.75	5.5	0.8	0.9	**0.8**	38 2	38.49
Low Temp Tar				83	8.2	7.4	0.6	**0.8**	38.75	37.94
SOLID FUELS										
Charcoal	89.31	93.88	1.02	92 04	2.45	2.96	0.53	**1**	34.39	34.78
Oak char (565C)	55 6	27.1	17.3	64.6	2.1	15.5	0.4	**0.1**	23.05	23.06
Casuarina Char (950C)	71.53	15.23	13.24	77 54	0 93	5.62	2.67	**0**	27.12	27.26
Coconut Shell Char (750C)	87.17	9393	2.9	88 95	0.73	6.04	1.38	**0**	31.12	31.21
Eucalyptus char (950C)	70.32	19.22	10.45	76.1	1 33	11.1	1.02	**0**	27 6	26.75

APPENDIX B – SETTLEMENT AGREEMENT

SETTLEMENT AGREEMENT

This Settlement Agreement (the "Agreement") is made effective and entered into as of October 12, 2009, by and among Sierra Club, and the Idaho Conservation League ("ICL") (Sierra Club and ICL, are collectively referred to as the "Contestants"), and Southeast Idaho Energy LLC ("SIE"), a Delaware limited liability company authorized to conduct business in Idaho. Sierra Club, ICL, and SIE are collectively referred to as the "Parties" and each is individually referred to as a "Party."

WHEREAS, SIE received an air quality Permit to Construct ("PTC") issued by the Idaho Department of Environmental Quality ("IDEQ") on February 10, 2009, authorizing construction of the Power County Advanced Energy Center in American Falls, Idaho (the "Project").

WHEREAS, the Contestants have concerns that were not addressed to their satisfaction in the PTC.

WHEREAS, on November 29, 2008, ICL filed a Notice of Protest before the Idaho Department of Water Resources.

WHEREAS, on March 18, 2009, the Contestants filed a Petition for Contested Case ("Petition") before the Board of the Idaho Department of Environmental Quality ("Board") seeking review and revision of the PTC.

WHEREAS, on April 8, 2009, SIE filed a Petition to Intervene in the contested case proceeding before the Board and requested that SIE be granted intervention as a matter of right.

WHEREAS, on March 18, 2009, the Parties filed a Stipulation to Stay the Proceedings before the Board, and on April 16, 2009, the Parties filed a Second Stipulation to Stay the Proceedings before the Board.

WHEREAS, the Parties worked together to address the concerns of Sierra Club and ICL, so as to avoid the need for litigation.

WHEREAS, this Agreement contains agreements to secure additional conditions in SIE's Permit to Construct.

WHEREAS, this Agreement is conditioned upon IDEQ's issuance of the modified PTC described in paragraph 1 that incorporates the limits described in this Agreement and is otherwise no less stringent than the PTC issued February 10, 2009.

WHEREAS, the Parties to this Agreement agree that the settlement agreement executed in September 2009 is superseded and void upon execution of this Agreement.

NOW, THEREFORE, for and in consideration of the above premises and the mutual agreements contained in this Agreement, and the satisfaction of the conditions precedent set forth in this Agreement, the Parties, intending to be legally bound, subject to the contingencies contained herein, agree as follows:

1. **Permit Modification.** This Agreement and the obligations and covenants set forth herein are subject to IDEQ issuing a final, modified PTC (the "Modified PTC") that substantively reflects the following conditions and is acceptable to the Parties:

1.1 Limitation on Gasification Island Startups. The Modified PTC will limit the number of planned startups when using coal or petcoke as fuel for the Gasification Island of the Project to thirteen (13) events during a rolling 12 month period, as set forth in Appendix A.

1.2 Boilers. The Modified PTC will require that SIE install Selective Catalytic Reduction ("SCR") and oxidation catalyst on the steam super-heater, as set forth in Appendix A. The Modified PTC will require that SIE install and operate a continuous emissions monitoring system ("CEMS") to monitor emissions of carbon monoxide ("CO"), as set forth in Appendix A. The Modified PTC will include emissions limits of 5 ppm for NOx and 20 ppm for CO, as set forth in Appendix A.

1.3 Fugitive Component Leaks. The Modified PTC will include a fugitive equipment CO emissions limit defined as fugitive emissions of CO from the outlet of the gasifier to the outlet of the final shift reactor that is equal to 31 tpy on a 12-month rolling average. In addition, Section 7.9.1 will be modified to require that the Fugitive CO Best Management Practices ("BMP") Plan be designed to determine compliance with this limit.

1.4 PM from Ammonium Nitrate Neutralizer Vent. The Modified PTC will require that SIE install drift and mist eliminators and a condenser on the Ammonium Nitrate neutralizer vent to control particulate matter (PM), as set forth in Appendix A.

1.5 Nitrous Oxide Reduction. The Modified PTC will include an emissions limit of 300 ppmv for nitrous oxides ("N_2O") from the Nitric Acid Plant, as set forth in Appendix A.

1.6 Nitric Acid Plant SCR. The Modified PTC will require SIE to limit nitrogen oxides ("NOx") emissions from the Nitric Acid Plant to 0.60 lbs of NOx per ton of pure acid by deploying extended absorption and SCR.

1.7 CO_2 Limit. It is the intention of the Parties to limit carbon dioxide ("CO_2") emissions from the Project to be equivalent to a natural gas based facility. Therefore, the Modified PTC will require SIE to limit and monitor CO_2 emissions from the Selexol AGR Stream 2 CO_2 Vent as set forth in the Modfied PTC in Appendix A and in the CO_2 Capture and Storage Agreement in Appendix B.

2. **Withdrawal of Contested Case Petition and Filing of Dismissal.** Provided that IDEQ issues the Modified PTC in accordance with this agreement, within five (5) days of issuance of the Modified PTC, Contestants, jointly and severally, will withdraw with prejudice the Petition and will file a Stipulation for Dismissal of the Proceeding with prejudice before the Board, in the format attached in Appendix C. In the event that the Contestants fail to withdraw the contested case Petition and to file a Stipulation for Dismissal in accordance with this Section 2, then Contestants, jointly and severally, authorize SIE, on their behalf, to execute and file the Stipulation for Dismissal attached in Appendix C. Provided IDEQ issues the Modified PTC in accordance with this agreement, Contestants agree not to challenge the Modified PTC. However, if an outside party challenges the Modified PTC, Contestants may petition to intervene to help defend the Modified PTC.

3. **Withdrawal of Notice of Protest.** Within five (5) days of issuance of the Modified PTC, ICL further agrees to withdraw with prejudice the Notice of Protest filed with the Idaho Department of Water Resources, in the format attached in Appendix D. In the event that ICL fails to withdraw the Notice of Protest, in accordance with this Section 3, ICL authorizes SIE, on its behalf, to execute and file the withdrawal attached in Appendix D.

4. **Representations.** Each Party represents and warrants to the other Parties that:

4.1 Authority. It has the power and authority, and the legal right, to make, deliver, and perform this Agreement and has taken all necessary action to authorize the execution, delivery, and performance of this Agreement. This Agreement has been duly executed and delivered by it. This Agreement constitutes a valid and binding obligation of the representing Party, enforceable against the representing Party in accordance with its terms.

4.2 No Legal Bar. The execution, delivery, and performance of this Agreement will not violate any applicable law or contractual obligation of the representing Party.

4.3 No Consent Required. Except for the Modified PTC, and the filings with the Board and the Idaho Department of Water Resources, as expressly provided in Sections 1, 2, and 3 of this Agreement, no consent or authorization of, filing with, notice to or other act by or in respect of, any governmental authority or any other person or entity is required in connection with the execution, delivery, performance, validity or enforceability of this Agreement.

5. **General Provisions.** The Parties further agree as follows:

5.1 Captions. The section headings of this Agreement are inserted for convenience only, and shall not constitute a part of this Agreement in construing or interpreting any provision hereof.

5.2 Termination. This Agreement shall terminate if the IDEQ has not issued the Modified PTC on or before November 30, 2009. If this Agreement is terminated as set forth in this paragraph 5.2, this Agreement shall be of no further force or effect and no Party shall have any further rights or obligations hereunder; and in such event the Parties agree that this Agreement may not be introduced as evidence in any subsequent evidentiary proceeding, provided, however, that in the event that this Agreement is terminated, no Party shall object to the resumption of the pending contested case proceeding appealing the original PTC and filed on March 18, 2009, or the Notice of Protest before the Idaho Dept. of Water Resources, regardless of the passage of time.

5.3 Amendment. This Agreement may be amended or modified only by written agreement signed by the Parties.

5.4 Counterpart Signatures. This Agreement may be signed in any number of counterparts with the same effect as if the signatures to each counterpart were upon a single instrument, and all such counterparts shall be deemed a single original of this Agreement.

5.5 Notices. All notices, reports, requests and other communications required or permitted by this Agreement or by law to be served upon or given to a party by the other party shall be deemed duly served and given when received after being delivered by hand or courier service or certified mail, return receipt requested, postage prepaid, to the addresses set forth below. In addition, notices shall be sent via fax and/or email when possible. Any party may change its address for the purposes of this Section by giving notice of change to the other party in the manner provided in this Section.

If to Sierra Club:	Sierra Club Environmental Law Program 85 Second St., 2nd Floor San Francisco, CA 94105 415-977-5544 (phone) 415-977-5793 (fax) Attn: Andrea Issod and Joanne Spalding Email: Andrea.Issod@sierraclub.org Joanne.Spalding@sierraclub.org
Idaho Conservation League:	Idaho Conservation League P.O. Box 844 Boise, ID 83701 Attn: Justin Hayes 208.344.0344 (fax) Email: jhayes@wildidaho.org
Southeast Idaho Energy, LLC:	Southeast Idaho Energy, LLC 621 17th Street, Ste. 1640 Denver, CO 80293 Attn: Matt Lee, Executive Vice President Email: m.lee@rehinc.com

5.6 Entire Agreement. This Agreement, including Appendices A, B, C, and D embodies the entire agreement and understanding of the Parties and replaces all prior negotiations and proposed agreements, written or oral, relating to the matters covered by the Agreement. Appendices A and B constitute enforceable agreements between the parties.

5.7 Governing Law. This Agreement shall be construed in accordance with and governed by the laws of the state of Idaho. Any disputes arising in connection with the execution or operation of this Agreement shall be governed and determined by the applicable laws of the state of Idaho. Available relief may include specific performance, equitable relief, or other remedy provided by Idaho law.

5.8 Expenses. Each Party shall bear its own expenses related to the negotiation and preparation of this Agreement and the satisfaction of their respective obligations contemplated in this Agreement.

5.9 Further Assurances. Each Party agrees to execute and deliver such further documents and do such further acts as any other Party shall reasonably require in order to assure and confirm to the Parties the rights created by this Agreement or by any other document executed in connection herewith or to facilitate the full performance of the terms of this Agreement and the other documents executed in connection herewith.

5.10 Parties Exclusive Remedies The Parties' sole and exclusive remedy for breach of this Agreement shall be an action for specific performance, injunction, or declaratory judgment. In no event shall any party be entitled to monetary damages for breach of this Agreement. In addition, no legal action for specific performance, injunction, or declaratory judgment shall be brought or maintained until: (a) the non-breaching party provides written notice to the breaching party that explains with particularity the nature of the claimed breach, and (b) within thirty (30) days after receipt of said notice, the breaching party fails to cure the claimed breach or, in the case of a claimed breach that cannot be reasonably cured within a thirty (30) day period, the breaching party fails to commence thereafter and diligently complete the activities reasonably necessary to remedy the claimed breach.

If the grounds for Sierra Club's breach of this Agreement is an alleged initiation or joinder of a lawsuit or administrative proceeding, dismissal of the suit or administrative proceeding by or as to the Sierra Club constitutes a complete cure.

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed and delivered by the undersigned authorized representatives.

DATED this _______ day of ___________, 2009.

____

Representative for Sierra Club

DATED this _______ day of ___________, 2009.

____

Representative for Idaho Conservation League

DATED this 12th day of October, 2009.

____

Representative for Southeast Idaho Energy, LLC

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed and delivered by the undersigned authorized representatives.

DATED this 19 day of October, 2009.

Representative for Sierra Club

DATED this 14th day of October, 2009.

Representative for Idaho Conservation League

DATED this _______ day of ___________, 2009.

Representative for Southeast Idaho Energy, LLC

APPENDIX B
CO_2 CAPTURE AND STORAGE AGREEMENT

Definitions

"**Covered CO_2**" is defined as carbon dioxide associated with the gasification of coal or petcoke, as measured and reported according to terms defined further below.

"**Captured CO_2**" is defined as the portion of Covered CO_2 that is captured and sent to a destination for permanent sequestration.

"**Covered CO_2 Emissions**" are defined as any release of Covered CO_2 to the atmosphere, as measured and reported according to terms defined further below.

"**Mechanical Completion**" will be a defined term under the Project's Engineering, Procurement, and Construction Contract and means that the installation and construction of the Project has been completed, the equipment and systems are capable of safe, normal operations, and the Project is ready for start-up and testing.

"**Compliance Date**" is the date that is five (5) years after the Mechanical Completion date.

"**Permanent Sequestration**" shall have the meaning set forth in any applicable federal or state regulation that addresses CO_2 releases to the atmosphere in effect at the time of commencement of operation of the Project. In the absence of federal or state regulation, this term shall mean the retention of CO_2 in a subsurface geologic containment system, such as a closed Enhanced Oil Recovery (EOR) field, that creates a high degree of confidence that substantially ninety-nine percent of the CO_2 will remain contained for at least one thousand years. Provided that SIE has taken all reasonable steps to ensure Permanent Sequestration, failure of the containment system to achieve ninety-nine percent containment shall not be a violation of this Agreement or the Modified Permit.

CO_2 Emissions

CO_2 Limit. By the Compliance Date, SIE shall limit Covered CO_2 Emissions by at least 58% (by weight) of Covered CO_2, to no more than 756,000[1] tons of CO_2 expressed as a twelve consecutive month rolling sum ("CO2 Limit"). Covered CO_2 in excess of the CO_2 Limit will be captured and sent to a destination for use in Enhanced Oil Recovery (EOR) and permanent sequestration ("Captured CO_2").

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[1] 756,000 tons per year of CO_2 is based on 58% reduction of Covered CO_2 from the Selexol AGR Stream 2: CO_2 Vent point source at full capacity.

Any Covered CO_2 Emissions greater than those allowed under the CO_2 Limit will be a violation of the Modified PTC.

The Parties acknowledge that SIE intends to transfer title to its CO_2 at the Project fence line and that compliance with federal standards or regulations, or with voluntary CO_2 sequestration protocols, will be the responsibility of the sequestering party. However, it is the explicit intent of SIE to ensure that the Captured CO_2 is permanently sequestered and SIE will take all reasonable steps to ensure Permanent Sequestration. Within thirty (30) days of executing a final contract with the CO_2 off-taker(s), SIE will provide a copy of the relevant excerpt of an executed agreement to Contestants. If Contestants have a good faith belief that the contract does not provide for Permanent Sequestration consistent with this agreement, Contestants shall have the right to bring a breach of contract claim. SIE may also provide Contestants will a draft of the agreement for comments.

SIE shall require its CO_2 off-taker(s) to develop semi-annual reports documenting compliance with Measurement, Monitoring, and Verification Plans ("MMV Reports"). SIE will provide copies of MMV Reports to the IDEQ.

<u>CO_2 Offsets</u>. During the period between Mechanical Completion and the Compliance Date ("Interim Period"), if SIE is not otherwise in compliance with the CO_2 Limit, SIE shall purchase greenhouse gas offsets on an annual basis equivalent to the difference between 58% of its Covered CO_2 (equal to 1.1 million tons per year of CO_2) and the amount of Captured CO_2. ("Required CO_2 Offsets").

Required CO_2 Offsets shall be federal or state regulated offsets. If a federal or state regulatory program is not in effect, SIE shall purchase offsets identified within the general region where the Project is located and acceptable to ICL. If such regional offsets are not available, SIE shall secure offsets acceptable to ICL through the California Climate Action Registry, the Gold Standard, the Voluntary Carbon Standard, the Chicago Climate Exchange, the Regional Greenhouse Gas Initiative, or such other nationally recognized voluntary program acceptable to ICL.

The cost of Required CO_2 Offsets purchased may be reduced, dollar for dollar, by any payment or penalty that SIE is assessed by any regulatory agency for failure of the Project to comply with the CO_2 Limit. If SIE is assessed any such payment or penalty, SIE shall give the Contestants notice, according to section 5.5, including a record of such penalties and SIE shall suggest the amount of reduction to which it is entitled. SIE shall obtain the consent of Contestants before taking any such reduction. Contestants shall not unreasonably withhold their consent.

<u>CO2 Monitoring and Reporting</u>

SIE shall comply with any applicable federal or state greenhouse gas emissions monitoring and reporting requirements in effect when the Project commences operation.

In the absence of federal or state greenhouse gas monitoring and reporting requirements that apply to the Project upon commencement of operation, SIE shall comply with the following provisions:

Monitoring.

SIE shall install a continuous volumetric flow meter (CMS) on the Selexol AGR Stream 2 CO2 Vent and on all major inlets and outlets entering or leaving the Selexol unit with an automated data acquisition and handling system (DAHS) for direct measurement, and will treat the flow as being 100% CO_2 for purposes of demonstrating compliance with the CO_2 Limit. SIE shall measure CO_2 emissions at least every 15 minutes and average hourly using the the daily volumetric data, a 100% CO_2 concentration by volume, and the density of pure CO_2 at the stack to atmosphere temperature and pressure.

Reporting.

SIE shall submit a monthly report to DEQ of the twelve consecutive month rolling sum of CO_2 emissions from the Selexol AGR Stream 2 CO_2 Vent, based upon the direct measurement of CO_2 collected by the installed flow meter. This report shall include total CO_2 emissions and a breakdown of CO_2 emissions by feedstock to account for emissions attributable to coal, petroleum coke, and other alternative feedstock. SIE shall maintain records of the data used to generate the reported emissions for five years.

Missing Data Procedures for Volumetric Flow and CO_2 Mass Rate.

SIE shall substitute for missing volumetric flow data from the CMS and DAHS using the procedures of paragraphs (a) or (b) of this section.

(a) In the event that only the flow meter on the CO_2 exhaust stack fails, SIE shall use necessary data from all inlet and outlet flow meters and steady state mass balance(s) to determine the missing volumetric flow rate of CO_2 to atmosphere; or

(b) In the event that a flow meter fails concurrent with the CO_2 exhaust flow meter, SIE shall determine substitute volumetric flow data as follows:

(1) During the first 720 quality-assured monitor operating hours following initial certification at a particular unit or stack location (i.e., the date and time at which quality-assured data begins to be recorded by a flow meter at that location), SIE shall provide substitute volumetric flow data according to the procedures in 40 C.F.R. §75.31(d) for determining volumetric flow as in effect as of the date hereof.

(2) Upon completion of 720 quality-assured monitor operating hours using the initial missing data procedures of 40 C.F.R. §75.31(d), SIE shall provide substitute data for volumetric flow in accordance with the procedures in 40 C.F.R. §75.33(c)(1) through (4) and (6) (as in effect as of the date hereof) for

determination of volumetric flow rate for emission sources that do not produce electrical or thermal output (nonload-based).

(c) In all cases, (a) and (b), SIE shall use the substitute volumetric flow data, a CO_2 concentration of 100% by volume, and the density of pure CO_2 at the stack temperature and pressure to determine the hourly mass flow rate of CO_2 to atmosphere.

To the extent that the CO2 Monitoring and Reporting provisions in this Agreement conflict with any provision of the Modified PTC, the provisions of the Modified PTC shall control.

Compliance with Federal and State Regulations

The Contestants agree that they will not challenge or protest a future modification of the Modified PTC to the extent that (i) such modification is made to comply with future laws and regulations and (ii) that such modification does not result in emission limits that are less stringent than those set forth in the Modified PTC. To the extent that the CO_2 Limit in the Modified PTC is less stringent than an applicable federal or state regulation, the Parties agree to find a mutually agreeable amendment to the CO_2 Limit to satisfy such federal or state regulation(s).