LIST OF EXHIBITS

Exhibit	Description
1	PSD Permit No. 021060ACB
2	Illinois Environmental Protection Agency Responsiveness Summary (June 2007)
3	Public Comments filed on behalf of the Sierra Club (Feb. 2007)
4	Transcript of Public Hearing on the PSD Permit (Jan. 11, 2007)
5	Sierra Club Press Release, "Bush EPA's Refusal to Follow Law on Trial at Supreme Court" (Nov. 2006)

217/782-2113

CONSTRUCTION PERMIT -- PSD APPROVAL

PERMITTEE

Christian County Generation, LLC
Attn: Michael L. McInnis
4350 Brownsboro Road, Suite 110
Louisville, Kentucky 40207

Application No.: 05040027 I.D. No.: 021060ACB
Applicant's Designation: IGCC PLANT Date Received: April 14, 2005
Subject: Integrated Gasification Combined Cycle Power Plant
Date Issued: June 5, 2007
Location: 1630 North 1400 East Road, Taylorville

Permit is hereby granted to the above-designated Permittee to CONSTRUCT emission sources and air pollution control equipment consisting of an Integrated Gasification Combined Cycle (IGCC) power plant comprised of three gasifiers and two syngas cleanup trains controlled by a flare; a sulfur recovery unit with tail gas treatment unit and thermal oxidizer; two combined cycle combustion turbines controlled by diluent (nitrogen) injection and selective catalytic reduction (SCR); cooling tower; bulk material handling; storage and loadout; a natural gas-fired auxiliary boiler; and other ancillary operations, as described in the above referenced application. This Permit is granted based upon and subject to the findings and conditions that follow.

In conjunction with this permit, approval is given with respect to the federal regulations for Prevention of Significant Deterioration of Air Quality (PSD) for the plant, as described in the application, in that the Illinois Environmental Protection Agency (Illinois EPA) finds that the application fulfills all applicable requirements of 40 CFR 52.21. This approval is issued pursuant to the federal Clean Air Act, the federal regulations promulgated thereunder at 40 CFR 52.21 for Prevention of Significant Deterioration of Air Quality (PSD), and a Delegation of Authority agreement between the United States Environmental Protection Agency (USEPA) and the Illinois EPA for the administration of the PSD Program. This approval becomes effective in accordance with the provisions of 40 CFR 124.15 and may be appealed in accordance with provisions of 40 CFR 124.19. This approval is based upon the findings that follow. This approval is subject to the following conditions. This approval is also subject to the general requirement that the plant be developed and operated consistent with the specifications and data included in the application and any significant departure from the terms expressed in the application, if not otherwise authorized by this permit, must receive prior written authorization from the Illinois EPA.

Exhibit 1

If you have any questions on this permit, please call Bob Smet at 217/782-2113.

Edwin C. Bakowski, P.E.
Acting Manager, Permit Section
Division of Air Pollution Control

ECB:RPS:psj

cc: Region 3
USEPA Region V

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SECTION 1: FINDINGS

1a. Christian County Generation, LLC (CCG) has requested a permit for an Integrated Gasification Combined Cycle (IGCC) power plant with a nominal capacity of 770 MW_e gross (630 MW_e net), utilizing coal as feedstock. The proposed plant would have three gasifiers (two active and one spare) each served by a gas cleanup system, including particulate matter, acid gas, and mercury removal. A flare would be present for startups and upsets. Electrical power would be generated in two combined cycle turbines (nominal 232 MW, each) and one steam turbine (nominal 306 MW). Other emission units would include: feedstock handling and storage, slag handling and storage, cooling tower, an auxiliary boiler, and ancillary operations.

b. The design coal supply for the plant would be Illinois coal nominally containing 4.3 percent sulfur by weight and 10,750 Btu per pound as received at the plant. The design feed rate of coal to the gasifiers would be 277 tons of coal per hour. Natural gas would be used for startup of the gasifiers prior to feeding coal.

2. The plant would be located in rural Christian County about two miles northeast of Taylorville. The site is in an area that is currently designated attainment for all criteria pollutants.

3. The proposed plant is a major source under the PSD rules. This is because the plant will have potential annual emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM), and carbon monoxide (CO) that are in excess of 100 tons. Emissions of sulfuric acid mist (H_2SO_4) are projected to be in excess of 7 tons per year, i.e., the significance thresholds for this pollutant. (Refer to Table I for the potential emissions of the plant.)

4. The proposed plant is not a major source for emissions of hazardous air pollutants (HAPs), i.e., as limited by this permit, the potential emissions from the plant will be less than 10 tons of an individual HAP (e.g., hydrogen chloride and hydrogen fluoride), and will be less than 25 tons in aggregate for total HAPs. Therefore, the plant is not subject to National Emission Standards for Hazardous Air Pollutants, adopted by USEPA under 40 CFR 63 or to review under Section 112(g) of the federal Clean Air Act.

5a. After reviewing the materials submitted by CCG, the Illinois EPA has determined that the project will (i) comply with applicable Board emission standards, (ii) comply with applicable federal emission standards, and (iii) utilize Best Available Control Technology (BACT) on emission units as required by PSD.

b. The determination of BACT made by the Illinois EPA for the proposed plant is the control technology determinations contained in the permit conditions for specific emission units.

6. The air quality analysis submitted by CCG and reviewed by the Illinois EPA shows that the proposed project will not cause or contribute to violations of the National Ambient Air Quality

Standard for NO_x, SO_2, PM, and CO. The air quality analysis shows compliance with the Class II allowable increment levels established under the PSD regulations.

7. The Illinois EPA has determined that the application for the proposed plant complies with all applicable Illinois Pollution Control Board Air Pollution Regulations and the federal Prevention of Significant Deterioration of Air Quality Regulations (PSD), 40 CFR 52.21.

8. In conjunction with the issuance of this construction permit, the Illinois EPA is also issuing an Acid Rain permit for the proposed plant to address requirements of the federal Acid Rain program. The combustion turbines would be affected units under the Acid Rain Deposition Control Program pursuant to Title IV of the Clean Air Act. As affected units under the Acid Rain Program, CCG must hold SO_2 allowances each year for the actual emissions of SO_2 from the turbines. The turbines are also subject to emissions monitoring requirements pursuant to 40 CFR Part 75. As the Acid Rain permit relates to the Acid Rain Program, it is not considered part of the PSD approval.

9. A copy of the application, the project summary prepared by the Illinois EPA, a draft of this construction permit, and a draft of the Acid Rain permit were placed in a nearby public repository, and the public was given notice and an opportunity to examine this material and to participate in a public hearing and to submit comments on these matters.

SECTION 2: IDENTIFICATION OF SIGNIFICANT EMISSIONS UNITS

Unit Number	Emission Unit	Emission Controls
1	Gasifiers and Syngas Cleanup Trains	
a	Normal Operation	Sulfur recovery unit with tail gas treatment and thermal oxidizer.
b	Startup/Malfunction/ Breakdown/Shutdown	Good operating practices and flare.
2	Combustion Turbines	Use of clean fuel (cleaned syngas and natural gas), good combustion practices, nitrogen diluent injection and selective catalytic reduction (SCR).
3	Material Handling	Enclosure, filter control, and suppression.
4	Cooling Tower	High efficiency drift eliminators.
5	Natural Gas-Fired Auxiliary Boiler	Low-NO_x burners and good combustion practices.
6	Roadway and Open Areas	Dust suppression and dust control program.

SECTION 3: SOURCE-WIDE PERMIT CONDITIONS

CONDITION 3.1: EFFECT OF PERMIT

a. This permit does not relieve the Permittee of the responsibility to comply with all local, state and federal regulations that are part of the applicable Illinois' State Implementation Plan, as well as all other applicable federal, state and local requirements.

b. In particular, this permit does not relieve the Permittee from the responsibility to carry out practices during the construction and operation of the plant, such as application of water or dust suppressant sprays to unpaved traffic areas, as necessary to minimize fugitive dust and prevent an air pollution nuisance from fugitive dust, as prohibited by 35 IAC 201.141.

CONDITION 3.2: VALIDITY OF PERMIT AND COMMENCEMENT OF CONSTRUCTION

a. This permit shall become invalid if construction is not commenced within 18 months after this permit becomes effective, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable period of time, pursuant to 40 CFR 52.21(r)(2) and 40 CFR 63.43(g)(41). Illinois EPA may extend the 18-month period upon a satisfactory showing that an extension is justified. This condition supersedes Standard Condition 1.

b. For purposes of the above provisions, the definitions of "construction" and "commence" at 40 CFR 54.21 (b)(8) and (9) shall apply, which requires that a source must enter into a binding agreement for on-site construction or begin actual on-site construction. (See also the definition of "begin actual construction," 40 CFR 54.21 (b)(11)).

CONDITION 3.3: STATUS OF THE SOURCE RELATIVE TO HAZARDOUS AIR POLLUTANTS (HAPs)

a. This source will not be a major source of hazardous air pollutants (HAP) so that the provisions of 40 CFR Part 63, and Section 112(g) of the Clean Air Act will not apply.

b. Although the plant is not a major source of HAPs for purposes of Section 112 of the Clean Air Act, for the gasification units, the Permittee shall comply with all applicable requirements contained in 40 CFR Part 63, Subpart A. In particular, for the gasification units, the Permittee shall comply with the following applicable requirements of 40 CFR 63 Subpart A, related to startup, shutdown, and malfunction, as defined at 40 CFR 63.2:

   i. The Permittee shall at all times, including periods of startup, shutdown, and malfunction as defined at 40 CFR 63.2, operate and maintain emission units at the source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions to the levels required by the relevant standards, i.e., meet the emission standard(s) or comply with the applicable Startup, Shutdown, and Malfunction Plan (Plan), as required below. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Illinois EPA and USEPA, which may include, but is not limited to, monitoring results, review of operation and maintenance procedures (including the Plan), review of operation and maintenance records, and inspection of the unit. [40 CFR 63.6(e)(1)(i)]

ii. The Permittee shall correct malfunctions as soon as practicable after their occurrence in accordance with the applicable Plan. To the extent that an unexpected event arises during a startup, shutdown, or malfunction, the Permittee shall comply by minimizing emissions during such a startup, shutdown, and malfunction event consistent with safety and good air pollution control practices. [40 CFR 63.6(e)(1)(ii)]

c. The Permittee shall develop, implement, and maintain written Startup, Shutdown, and Malfunction Plans (Plans) that describe, in detail, procedures for operating and maintaining the various emission units at the plant during periods of startup, shutdown, and malfunction and a program of corrective action for malfunctioning process, air pollution control and monitoring equipment used to comply with the relevant emission standards and emission control requirements. These Plans shall be developed to satisfy the purposes set forth in 40 CFR 63.6(e)(3)(i)(A), (B) and (C). The Permittee shall develop its initial plans prior to the initial commencement of operation of emission unit(s).

i. During periods of startup, shutdown, and malfunction of an emission unit, the Permittee shall operate and maintain such unit, including associated air pollution control and monitoring equipment, in accordance with the procedures specified in the applicable Plan required above. [40 CFR 63.6(e)(3)(ii)]

ii. When actions taken by the Permittee during a startup, shutdown, or malfunction (including actions taken to correct a malfunction) are consistent with the procedures specified in the applicable Plan, the Permittee shall keep records for that event which demonstrate that the procedures specified in the Plan were followed. In addition, the Permittee shall keep records of these events as specified in 40 CFR 63.10(b), including records of the occurrence and duration of each startup, shutdown, or malfunction of operation and each malfunction of the air pollution control and monitoring equipment. Furthermore, the Permittee shall confirm in the periodic compliance report that actions taken during periods of startup, shutdown, and malfunction were consistent with the applicable Plan, as required by 40 CFR 63.10(d)(5). [40 CFR 63.6(e)(3)(iii)]

iii. If an action taken by the Permittee during a startup, shutdown, or malfunction (including an action taken to correct a malfunction) of an emission unit is not consistent with the procedures specified in the applicable Plan, and the emission unit exceeds a relevant emission standard, then the Permittee must record the actions taken for that event and must promptly report such actions as specified by 40 CFR 63.6(d)(5), unless otherwise specified elsewhere in this permit or in the CAAPP Permit to be issued for the plant. [40 CFR 63.6(e)(3)(iv)]

iv. The Permittee shall make changes to the Plan for an emission unit if required by the Illinois EPA or USEPA, as provided for by 40 CFR 63.6(e)(3)(vii), or as otherwise required by 40 CFR 63.6(e)(viii). [40 CFR 63.6(e)(3)(vii) and (viii)]

v. These Plans are records required by this permit, which the Permittee must retain in accordance with the general requirements for retention and availability of records (General Permit Condition 6). In addition, when the Permittee revises a Plan, the Permittee must also retain and make available the previous (i.e., superseded) version of the Plan for a period of at least 5 years after such revision. [40 CFR 63.6(e)(v) and 40 CFR 63.10(b)(1)]

d. For the purpose of this condition and other conditions of this permit for which the regulatory definitions of the terms "startup," "shutdown" and "malfunction" under the NSPS are not applicable, the definitions of the terms "startup," "shutdown" and "malfunction" under the NESHAP, at 40 CFR 63.2, shall apply and be used.

CONDITION 3.4: MISCELLANEOUS ANCILLARY EQUIPMENT

a. i. Ancillary equipment shall be operated and maintained in accordance with good air pollution control practice to minimize emissions.

ii. The fuel fired in the main fire water pump engine shall be pipeline quality natural gas.

iii. A. Engines firing fuels other than natural gas shall only be used as emergency equipment, as defined at 35 IAC 211.1920.

B. The power output of such engines shall be no more than 1,500 horsepower.

C. Operation of such engines shall not exceed 500 hours per year, provided, however, that the Illinois EPA may authorize temporary operation of engines in excess of 500 hours per year to address extraordinary circumstances that require operation of this device, by issuance of a separate State construction permit addressing such circumstances.

iv. This permit is issued based on negligible emissions of each criteria pollutant from the cold cleaning degreaser. For this purpose, emissions shall not exceed nominal emission rates of 0.1 lb/hour and 0.44 ton/year.

v. This permit is issued based on negligible emissions of each criteria pollutant from the wastewater treatment plant. For this purpose, emissions shall not exceed nominal emission rates of 0.1 lb/hour and 0.44 ton/year.

Note: These requirements constitute the determination of Best Available Control Technology (BACT) for ancillary equipment, as required under the PSD rules.

b. i. The ancillary equipment shall comply with all applicable emission standards and control requirements of applicable federal New Source Performance Standards (NSPS), 40 CFR Part 60, including the NSPS for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII, for the engines at the plant.

ii. The ancillary equipment shall comply with all applicable emission standards and control of requirements of applicable state emission regulations at Title 35, Subtitle B, Chapter I, Subchapter c.

iii. The Permittee shall fulfill applicable requirements of applicable regulations, including provisions for testing, monitoring, recordkeeping, notification and reporting.

CONDITION 3.5: AUTHORIZATION TO OPERATE EMISSION UNITS

a. i. Under this permit, each gasifier, each syngas cleanup train, the sulfur recovery unit and each CT/HRSG may be operated for a period that ends 180 days after initial startup of the unit to allow for equipment shakedown and required emissions testing. This period may be extended by Illinois EPA upon request of the Permittee if additional time is needed to complete shakedown or perform emission testing. This condition supersedes Standard Condition 6. (See Attachment 2)

ii. Upon successful completion of emission testing of a unit demonstrating compliance with applicable requirements or limitations, the Permittee may continue to operate the unit as allowed by Section 39.5(5) of the Environmental Protection Act.

b. i. The remainder of the plant, excluding the above units, may be operated under this construction permit for a period of 365 days after initial startup of the first gasifier. This period of time may be extended by the Illinois EPA for up to an additional 365 days upon written request by the Permittee as needed to reasonably accommodate unforeseen difficulties experienced during shakedown of the plant. This condition supersedes Standard Condition 6. (See Attachment 2)

ii. Upon successful completion of applicable emission testing demonstrating compliance with applicable requirements or limitations, the Permittee may continue to operate the remainder of the plant as allowed by Section 39.5(5) of the Environmental Protection Act.

c. For emission units that are subject to federal New Source Performance Standards (NSPS), the Permittee shall fulfill applicable notification requirements of the NSPS, 40 CFR 60.7(a), including:

i. Written notification of commencement of construction no later than 30 days after such date [40 CFR 60.7(a)(1)]; and

ii. Written notification of the actual date of initial startup within 15 days after such date [40 CFR 60.7(a)(3)].

SECTION 4: UNIT-SPECIFIC CONDITIONS FOR PARTICULAR EMISSION UNITS

CONDITION 4.1: UNIT-SPECIFIC CONDITIONS FOR THE GASIFICATION BLOCK

4.1.1 Emission Unit Description

The affected units for the purpose of these unit-specific permit conditions are the various emission streams from the gasification block. The gasification block is the first part of Integrated Gasification Combined Cycle (IGCC) technology, in which a feedstock is converted into a synthetic fuel gas or "syngas". Syngas produced in the gasifiers will be the primary fuel fired in the combined cycle combustion turbines which are the second part of IGCC technology.

The gasification block would have three identical gasifiers. Only two gasifiers would normally be operated, with the third gasifier acting as a reserve or spare to allow the plant to operate at capacity during required maintenance or other outage of one of the gasifiers.

The gasification block would also have two identical gas cleanup trains, each designed to process the syngas produced by one gasifier. In the cleanup trains the raw syngas would be processed to remove contaminants in the raw gas that would otherwise lead to emissions when the gas was used. These contaminants include: 1) mercury; 2) non-slag fire ash, which would otherwise be emitted as particulate matter; and 3) sulfur compounds, which would otherwise be emitted as sulfur dioxide (SO_2). During maintenance or other outage of a gas cleanup train, the plant would run on half capacity with a single train.

During normal operation, the only emission points from the gasification block would be the natural gas fired pilot flame in the flare and the exhaust from the sulfur recovery unit. The sulfur recovery unit uses the Claus Process to convert the sulfur compounds recovered from the raw syngas into sulfur, a secondary product from the plant. The emissions of SO_2 from the sulfur recovery unit would be controlled by a tail gas treatment system to reduce the amount of SO_2 emissions, and an oxidizer to assure that emissions occur as SO_2 rather than hydrogen sulfide (H_2S).

During startup or upsets of a gasifier or gas cleanup train, in addition to emissions from the sulfur recovery unit, the gasification block would also have process emissions from the flare from disposal of off-specification syngas in the flare. These emissions are minimized as these events are themselves minimized and act to disrupt normal operation of the plant. In addition, flared syngas would typically have undergone cleaning prior to flaring.

4.1.2-1 Control Technology Determination for Gasification Block Units

a. Each gasification train shall be operated and maintained with the following features to minimize and control emissions.

i. A closed vent system, which shall be designed and maintained so that any discharge of syngas or other process gas from the gasifiers or gas cleanup trains that is not sent to the power block can be reintroduced into the gasification block or vented to a flare for disposal. This requirement does not apply to air or nitrogen introduced into unit(s) during periods when a unit is shut down, as might be needed for purposes of maintenance or to purge unit(s) in preparation for startup. This requirement also does not apply to any gas streams sent to the sulfur recovery unit.

ii. A flare or flares, which shall be designed, operated and maintained to comply with all relevant requirements of 40 CFR 60.18.

iii. A gas cleanup system for the syngas for removal of sulfur compounds, which shall be conducted with an adsorption solvent with a low organic vapor pressure, such as Selexol solvent, or a formal Leak Detection and Repair Program shall be implemented to address potential emissions from leaking components, in accordance with the relevant provisions of 40 CFR 60, Subpart VV.

iv. A Claus-type sulfur recovery unit or other unit for processing the sulfur in the hydrogen sulfide (H_2S) rich gas stream produced from regeneration of the adsorption solvent used for control of sulfur compounds into a stable product or waste.

v. Good operating practices.

b. The gasification block shall be operated to comply with the following work practices:

i. All discharges of syngas or other process gas shall be vented to a flare through the closed vent system, except when a failure of equipment or planning preclude the safe disposal of a gas stream in this manner.

ii. The operating level of gasifiers at any time shall not exceed the actual working capacity of the gas cleanup trains at such time.

iii. Sour gas shall not be flared except when a malfunction or breakdown, due to either failure of equipment or planning, precludes the safe processing of the sour gas by a gas cleanup train.

iv. All H_2S gas streams produced by cleanup of syngas shall be processed by the sulfur recovery unit except as this is precluded due to startup, shutdown, malfunction or breakdown of this unit, in which case the stream shall be flared.

c. The good air pollution control practices used for the gasifiers and gas cleanup trains to minimize emissions shall include the following:

   i. Operation of units in accordance with written operating procedures that include startup, shutdown and malfunction plan(s) (See also Condition 3.3);

   ii. Inspection, maintenance and repair of units in accordance with written maintenance procedures including:

      A. Appropriate practices to minimize emissions during startup, shutdown and malfunction, as further addressed in Condition 4.1.5(c).

      B. Coordination of the startup of gas cleanup train(s) with the startup of the gasifier(s) so as to minimize emissions, prior to introduction of syngas to the combustion turbines.

   iii. Use of natural gas during startup of a gasifier to preheat the gasifier prior to introduction of feedstock into the gasifier.

4.1.2-2 Control Technology Determination for the Sulfur Recovery Unit

a. The sulfur recovery unit shall be operated and maintained with a tail-gas treatment system followed by a thermal oxidizer.

b. i. The emissions of SO_2 from the sulfur recovery unit shall not exceed 100 ppm by volume (dry basis) at 0% oxygen except during startup, shutdown, malfunction or breakdown.*

   ii. During periods of startup, shutdown, malfunction or breakdown,* emissions of SO_2 from the sulfur recovery unit shall not exceed 201 lbs/hour, based on a 3-hour average.

   * For breakdowns, the alternative emission limit shall only apply for the three-year period following commencement of operation of the gasification block. After this period, the SO_2 emissions of the sulfur recovery unit shall not exceed 100 ppm except during startup, shutdown or malfunction.

c. Good air pollution control practices shall be used for the sulfur recovery unit to minimize emissions, including the measures specified in Condition 4.1.2-1(c)(i) and (ii), during startup, shutdown and malfunction, as further addressed in Condition 4.1.5(c).

   Note: These requirements are applicable for emissions of SO_2 for which continuous emissions monitoring is performed and the numerical limits in Condition 4.1.2-2(b)(ii) address emissions during startup, shutdown and malfunction, as well as for emissions of PM, NO_x and CO. For emissions of PM, NO_x and CO applicable lbs/hour limits in Condition 4.1.6(b), do apply during such periods and serve as "secondary limits" for purposes of BACT, with compliance determined based on engineering analysis and calculations.

4.1.3-1 Applicable Federal Emission Standards

None

4.1.3-2 Applicable State Emission Standards

Each emission unit in the gasification block is subject to the following state emission standards.

a. The emission of smoke or other particulate matter from an emission unit shall not have opacity greater than 30 percent, pursuant to 35 IAC 212.123(a), except as authorized 35 IAC Part 201 Subpart I.

b. The emissions of SO_2 into the atmosphere shall not exceed 2000 ppm, pursuant to 35 IAC 214.301.

4.1.4 Non-applicability of Regulations of Concern

a. This permit is issued based on units in the gasification block not being subject to state emission standards for fuel combustion emission units because the purpose of the gasification block is to produce and process syngas and any recovery of heat from the gasification block is incidental to this purpose.

b. This permit does not address the control requirements of 35 IAC 215.301, Use of Organic Material, for units in the gasification block, as all emissions of organic material from such units are to be flared, which will assure compliance with the alternative standard of 35 IAC 215.302, providing at least 85% control.

4.1.5 Operating Requirements

a. The sulfur storage facility for the sulfur recovery unit shall be vented back into the sulfur recovery unit or the associated tail gas treatment unit.

b. The tail gas thermal oxidizer operating temperature shall be at least the temperature during emissions testing of the oxidizer.

c. The Permittee shall operate each gasification train, the sulfur recovery unit and associated air pollution control equipment in accordance with good air pollution control practice to minimize emissions, by operating in accordance with detailed written operating procedures as it is safe to do so. These procedures at a minimum shall:

i. Address startup, normal operation, shutdown and malfunction events.

ii. Fulfill applicable requirements of Condition 3.3 for a Startup, Shutdown and Malfunction Plan, including detailed provisions for review of relevant operating parameters of the gasification train during startup, shutdown and malfunction as necessary to make adjustments and corrections to reduce or eliminate any excess emissions.

iii. With respect to startup address readily foreseeable startup scenarios, including so called "hot startups" when the operation of a gasifier or gas cleanup train, or sulfur recovery unit, is only temporarily interrupted, and provide for appropriate review of the operational condition of a unit prior to initiating startup.

iv. A. With respect to malfunction, identify and address likely malfunction events with specific programs of corrective actions, and provide that upon occurrence of a malfunction that will result in emissions in excess of the applicable limits in Condition 4.1.2, 4.1.3 and 4.1.4, the Permittee shall, as soon as practicable, repair the affected equipment, reduce the operating rate of the gasification train or remove the gasification train from service so that excess emissions cease.

B. Consistent with the above, if the Permittee has maintained and operated the trains and sulfur recovery unit so that malfunctions are infrequent, sudden, not caused by poor maintenance or careless operation, and in general are not reasonably preventable, the Permittee shall begin shutdown of a train within 90 minutes, unless the malfunction is expected to be repaired within 120 minutes or such shutdown could threaten the stability of the regional electrical power supply. In such case, shutdown shall be undertaken when it is apparent that repair will not be accomplished within 120 minutes or shutdown will not endanger the regional power system. In no case shall shutdown be delayed solely for the economic benefit of the Permittee.

Note: If the Permittee determines that the continuous emission monitoring system (CEMS) for the sulfur recovery unit is inaccurately reporting excess emissions, the unit may continue to operate provided the Permittee records the information it is relying upon to conclude that the unit and associated emission control systems are functioning properly and the CEMS is reporting inaccurate data and the Permittee takes prompt action to resolve the accuracy of the CEMS.

d. The Permittee shall handle the feedstock for the gasifiers in accordance with a written Feedstock Management Plan that shall be designed to provide the gasifiers with a consistent feedstock supply that meets relevant criteria needed for proper operation of the gasifiers and production of a syngas that can be reliably processed by the gas cleanup train.

e. The Permittee shall review its operating and maintenance procedures for units and its feedstock management plan for gasifiers, as required above on a regular basis and revise them if needed consistent with good air pollution control practice based on actual operating experience and equipment performance. This review shall occur at least annually if not otherwise initiated by occurrence of a startup, shutdown, malfunction or breakdown that is not adequately addressed by the existing plans or a specific request by the Illinois EPA for such review.

4.1.6 Emission Limitations

a. Emissions from the gasification block (flare) shall not exceed the limits in Attachment 1, Table III.

b. i. The emissions of the sulfur recovery unit shall not exceed the following limits. Compliance with short-term limits in lbs/hour shall be determined on a 24-hour average for NO_x and CO and a 3-hour average for other pollutants.

Pollutant	Short Term (Pound/Hour)		Annual Total (Tons/Year)
	Normal	Other*	
SO_2	20.82	201.0	91.2
NO_x	16.40	117.0	71.9
CO	9.50	70.3	41.5
PM	0.63	6.4	2.8
VOM	0.63	4.7	2.8

* Periods of startup, shutdown and malfunction.

ii. Emissions of SO_2 from the sulfur recovery unit during startup shall not exceed 0.8 tons per individual startup and 45 tons per year.

4.1.7-1 Operational Testing for the Flare

Within 10 days of initial startup of any unit in the gasification block, the Permittee shall conduct tests of the flare to confirm compliance with relevant requirements of 40 CFR 60.18.

4.1.7-2 Emission Testing for the Sulfur Recovery Unit

a. i. Within 60 days after achieving the maximum production rate at which the sulfur recovery unit will be operated but not later than 180 days after initial startup of the unit, the Permittee shall have tests conducted for opacity and emissions of NO_x, SO_2, hydrogen chloride, hydrogen fluoride, and mercury and other metals as follows at its expense by an approved testing service while the unit is operating in the maximum range and other representative operating conditions.

ii. This period of time may be extended by the Illinois EPA for up to an additional 365 days upon written request by the Permittee as needed to reasonably accommodate unforeseen difficulties in the startup and testing of the gasification block, provided that preliminary emissions measurements are conducted and reported to the Illinois EPA.

iii. In addition to the emission testing required above, the Permittee shall perform emission tests as provided below as requested by the Illinois EPA for the sulfur recovery unit within 45 days of a written request by the Illinois EPA or such later date agreed to by the Illinois EPA.

Note: Specific requirements for periodic emission testing may be established in the CAAPP Permit for the plant.

b. The following methods and procedures shall be used for testing, unless other methods adopted by or being developed by USEPA are specified or approved by the Illinois EPA.

Opacity	Method 9
Location of Sample Points	Method 1
Gas Flow and Velocity	Method 2
Flue Gas Weight	Method 3 or 3A
Moisture	Method 4
Nitrogen Oxides	Method 19
Sulfur Dioxides	Method 19
Hydrogen Chloride	Method 26
Hydrogen Fluoride	Method 26
Metals[1]	Method 29
Reduced Sulfur Compounds	Method 15A

Notes:

1 For purposes of this permit, metals are defined as mercury, arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel.

c. i. Test plans, test notifications, and test reports shall be submitted to the Illinois EPA in accordance with the Condition 6.2.

ii. In addition to other information required in a test report, test reports shall include detailed information on the operating conditions of a gasifier during testing, including:

A. Feedstock consumption (in tons);

B. Composition of the feedstock (Refer to Condition 4.1.10(b)), including the metals, chlorine and fluorine content, expressed in pound per million Btu;

C. Firing rate (million Btu/hour) and other significant operating parameters of the gasifier;

D. Control device operating rates or parameter; and

E. Opacity of the exhaust from the flare and tail-gas thermal oxidizer, 6-minute averages and 1-hour averages.

4.1.8 Instrumentation

The Permittee shall install, calibrate, maintain, and operate an instrument that continuously monitors and records concentrations of SO_2 of the gases discharged into the atmosphere from the sulfur recovery unit tail-gas thermal oxidizer.

4.1.9-1 Operational Monitoring

a. The Permittee shall install, evaluate, operate, and maintain meters to measure and record consumption of feedstock and natural gas by each gasifier.

b. The Permittee shall install, operate and maintain monitoring systems to measure and record key operating parameters of the cleanup systems in each gas cleanup train, including:

i. Temperature at and pressure drop across each cleanup system (mercury, particulate and sulfur compounds);

ii. Flow rate of scrubbant in the particulate cleanup system; and

iii. Flow rate of adsorption solvent.

c. The Permittee shall install, operate and maintain monitoring systems related to venting of gas to a flare to measure and record:

i. The total flow of syngas or other process gas to the flare (in SCFM).

ii. For each category of syngas or other process gas that can be vented to the flare, for each gasifier and cleanup train, the date, time and duration of each occurrence of venting of gas to the flare.

d. The Permittee shall install, operate and maintain monitoring systems for the sulfur recovery system to measure and record the following:

   i. Combustion chamber temperature in the oxidizer.

   ii. The occurrence of venting of gas to the flare.

e. The Permittee shall maintain the records of maintenance and operational activity associated with these systems.

4.1.9-2 Sampling and Analysis of Feedstock and Syngas

a. i. The Permittee shall sample and analyze the sulfur and heat content of the feedstock supplied to the gasifiers in accordance with USEPA Reference Method 19 (40 CFR 60, Appendix A, Method 19).

   ii. The Permittee shall analyze samples of all feedstock supplies to the gasifiers and the feedstock supply itself for mercury and other metals, chlorine and fluorine content, as follows:

      A. Analysis shall be conducted in accordance with USEPA Reference Methods or other method approved by USEPA.

      B. Analysis of the feedstock supply to the gasifiers themselves shall be conducted in conjunction with performance testing of a combustion turbine (see Condition 4.2.7).

      C. Analysis of representative samples of feedstock shall be conducted in conjunction with acceptance of coal from a new mine or any alternate feedstock.

      D. Analysis of representative samples of feedstock shall be conducted at least every two years, if a more frequent analysis is not needed pursuant to the above requirements.

b. The Permittee shall take representative samples of the various gas streams that could be vented to the flare and analyze them using applicable ASTM methods for sulfur, chlorine, fluorine, and mercury and other metals content.

4.1.10-1 Recordkeeping for Units in the Gasification Block

a. The Permittee shall maintain the following records with respect to operation and maintenance of each gasifier and gas cleanup train:

i. An operating log for the unit that at a minimum shall address:

A. Each startup of the unit, including the nature of the startup, sequence and timing of major steps in the startup, any unusual occurrences during the startup, and any deviations from the established startup procedures, with explanation;

B. Each shutdown of the unit, including the nature and reason for the shutdown, sequence and timing of major steps in the shutdown, any unusual occurrences during the shutdown, and any deviations from the established shutdown procedures, with explanation; and

C. Each malfunction or breakdown of the unit that significantly impairs emission performance, including the nature and duration of the event, sequence and timing of major steps in the malfunction or breakdown, corrective actions taken, any deviations from the established procedures for such events, and preventative actions taken to address similar events.

ii. Inspection, maintenance and repair log(s) for each unit that at a minimum shall identify such activities that are performed related to components that may affect emissions; the reason for such activities, i.e., whether planned or initiated due to a specific event or condition; and any failure to carry out the established maintenance procedures, with explanation.

b. The Permittee shall maintain records of the following items related to feedstock used in the gasifiers:

i. Records of the sampling and analysis of feedstock supplied to the gasifiers conducted in accordance with Condition 4.1.9-2.

ii. A. The sulfur content of feedstock, lbs sulfur/million Btu, supplied to the gasifiers, as determined pursuant to Condition 4.1.9-2; and

B. The sulfur content of feedstock supplied to the gasifiers on a 30-day rolling average.

c. The Permittee shall keep records for any period during which any unit deviated from an applicable requirement. These records shall include at least the information specified by Condition 6.3.

4.1.10-2 Recordkeeping for the Sulfur Recovery Unit

a. The Permittee shall maintain the following records for the SO_2 instrumentation on the Tail Gas Recovery Unit/Thermal Oxidizer required by Condition 4.1.8 that at a minimum shall include:

i. Operating records for the SO_2 monitoring system, including:

A. SO_2 measurements;

B. Continuous monitoring system performance testing measurements;

C. Performance evaluations;

D. Calibration checks;

E. Maintenance and adjustment performed;

F. Quarterly reports submitted in accordance with Condition 4.1.12-2; and

G. Records to verify compliance with the limitations of Condition 4.1.6, including:

1. Hourly SO_2 emissions from the Sulfur Recovery Unit as derived from the data obtained by the SO_2 monitor, ppm; and

2. Other than during startup, any twelve-hour period when the average SO_2 concentration exceeded 150 ppm at zero percent oxygen on a dry basis.

H. Appropriate records to verify compliance with 35 IAC 212.123 [Condition 4.1.3-2(a)].

b. Operating Records

The Permittee shall maintain the following operating records that at a minimum shall include for each startup of the unit:

i. Date and duration of the startup, i.e., start time and time normal operation achieved;

ii. Whether the startup was a full startup or a startup associated with catalyst regeneration;

iii. If normal operation was not achieved within 4 days for a full startup and 48 hours for a startup associated with catalyst regeneration, an explanation why startup could not be achieved in normal time frame;

iv. A detailed description of the startup;

v. An explanation why established startup procedures could not be performed, if not performed;

vi. The nature of opacity, i.e., severity and duration, during the startup and the nature of opacity at the conclusion of startup, if above normal; and

vii. Whether exceedance of Condition 4.1.6 may have occurred during startup, with explanation and estimated duration (minutes).

c. Records for Continued Operation During Malfunctions and Breakdowns

The Permittee shall maintain records related to malfunction and breakdown that, as a minimum, shall include:

i. A maintenance and repair log for the unit and associated control equipment, listing each activity performed with date; and

ii. Records for each incident when operation of the unit continued during malfunction or breakdown with excess emissions including the following information:

A. Date and duration of malfunction or breakdown;

B. A detailed explanation of the malfunction or breakdown;

C. An explanation why continued operation of the Sulfur Recovery Unit was necessary;

D. The measures used to reduce the quantity of emissions and the event;

E. The steps taken to prevent similar malfunctions or breakdowns or reduce their frequency and severity; and

F. An estimate of the amount of excess emissions released during malfunction/breakdown.

d. The Permittee shall maintain records of the following items:

i. Amount of sulfur recovered; and

ii. Monthly and annual emissions of SO_2, PM, NO_x, H_2S, and CO.

4.1.11 Notifications

The Permittee shall notify the Illinois EPA within 30 days of deviations from applicable requirements that are not addressed by the regular reporting required below. These notifications shall include the information specified by Condition 6.5.

4.1.12-1 Reporting for Gasification Units

a. i. The Permittee shall report to the Illinois EPA any and all opacity and emission measurements for any unit in the gasification block (other than the sulfur recovery unit) that is in excess of the respective requirements set by this permit. These reports shall provide for each such incident, the pollutant emission rate, the date and duration of the incident, and whether it occurred during startup, malfunction, breakdown, or shutdown. If an incident occurred during malfunction or breakdown, the corrective actions and actions taken to prevent or minimize future reoccurrences shall also be reported.

ii. These reports shall also address any deviations from applicable compliance procedures for a unit established by this permit, including specifying periods during which the continuous monitoring systems were not in operation.

b. i. The Permittee shall keep the following operating records for each day that flaring occurs:

A. Date and amount of gas flared;

B. Confirmation that established operating procedures were followed; and

C. Confirmation that the flare functioned properly, i.e., a flame was present and no visible emissions were observed except as allowed by 40 CFR 60.18(f)(i).

ii. The Permittee shall keep the following records for each event when gas that was not fully cleaned was flared (or gas was sent directly to the atmosphere):

A. Date, time and duration of the event;

B. Description of the event;

C. Estimated amount of gas flared or emitted until the situation was corrected or emissions ceased;

D. Corrective actions taken; and

E. Actions taken to prevent or reduce the likelihood of future occurrences.

4.1.12-2 Reporting for the Sulfur Recovery Unit

a. The Permittee shall submit quarterly reports for SO_2 emissions from the Sulfur recovery Unit. These reports shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement indicating whether compliance with applicable emission standards and control requirements and minimum data requirements was achieved during the reporting period.

   i. The magnitude of excess emissions, any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions;

   ii. Specific identification of each period of excess emissions that occurs during startup, shutdown, or malfunctions of the Unit. The nature and cause of any malfunction (if known), the corrective actions taken or preventative measures adopted;

   iii. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and

   iv. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

   For the purposes of this report, an exceedance for SO_2 is any twelve-hour period during which the average concentration of SO_2 in the gases discharged into the atmosphere from the sulfur recovery unit exceeds 100 ppm at zero percent oxygen on a dry basis.

b. The Permittee shall provide the following notifications and reports to the Illinois EPA, concerning each incident when operation of the Sulfur Recovery Unit continued during malfunction or breakdown with excess emissions as addressed by Condition 4.1.10-2(c).

   i. The Permittee shall notify the Illinois EPA's regional office by telephone as soon as possible during normal working hours, but no later than three days, for each incident.

   ii. Upon completion of the incident, the Permittee shall give a written follow-up notice to the Illinois EPA, Compliance Section and Regional Field Office, within 15 days providing a detailed explanation of the event, an explanation why continued operation of the Sulfur Recovery Unit was necessary, the length of time during which operation continued under such conditions, the measures taken by the

Permittee to minimize and correct deficiencies with chronology, and when the repairs were completed or the amount of acid gas feed to the sulfur recovery unit was reduced.

c. The Permittee shall promptly notify the Illinois EPA of deviations of the Sulfur Recovery Unit with the permit requirements as follows. Reports shall describe the probable cause of such deviations, any corrective actions or preventive measures taken, and other information below.

   Along with the quarterly report for exceedances of the SO_2 limit. Within 30 days of exceedance of other limits in Condition 4.1.6, notifications shall also include:

   i. Identification of the limit that may have been exceeded;

   ii. Duration of the deviation;

   iii. An estimate of the amount of emissions in excess of the applicable limit;

   iv. A description of the cause of the deviation; and

   v. When compliance was reestablished.

CONDITION 4.2: UNIT-SPECIFIC CONDITIONS FOR THE COMBUSTION TURBINES (CTS)

4.2.1 Emission Unit Description

The affected units for the purpose of these unit-specific permit conditions are the two combined cycle combustion turbines (CT), used to produce electric power. The primary fuel for the turbines would be fuel gas (cleaned syngas from the gasification trains). The CTs would also have the capability to burn natural gas, which would be used for startup of the CTs and at times when the gasification trains are out of service and syngas is unavailable.

Exhaust from each CT will be directed to a heat recovery steam generator (HRSG). The HRSGs will not be equipped with duct burners. Steam generated in the HRSG, will be combined with high-pressure steam from the gasification block and sent to a steam turbine to generate additional electricity.

4.2.2 Control Technology Determination

a. Each CT shall be operated and maintained with the following features to control emissions:

i. Use of fuel gas (i.e., syngas, that has been processed by the syngas cleanup system) or natural gas to limit emissions of SO_2 and PM.

ii. A selective catalytic reduction (SCR) system and nitrogen diluent injection to control NO_x emissions; and

iii. Good combustion practices to minimize CO and VOM emissions.

b. The emissions from each CT shall not exceed the following limits. These limits are expressed in terms of fuel heat input to the CT, in million Btu, higher heating value. For limits which the specified compliance time period is a 3-hour block with provision for emissions testing, if test runs other than one-hour in duration are performed during emissions testing, the compliance time period during emission testing shall be the total actual duration of the test runs.

i. Filterable PM - 0.0090 lb/million Btu for syngas and 0.0070 lb/million Btu for natural gas, and

Total PM_{10} (filterable and condensable) - 0.0220 lb/million Btu for syngas and 0.0110 lb/million Btu for natural gas.

These limits shall apply as a 3-hour block average, with compliance determined by emission testing in accordance with Condition 4.2.7 and from equipment operation. These limits shall not apply during startup, shutdown or malfunction as addressed by Condition 4.2.2(d).

ii. SO_2 - 0.016 lb/million Btu for syngas and 0.001 lb/million Btu for natural gas.

These limits shall apply on a 3-hour block average, with compliance determined using continuous monitoring conducted in accordance with Condition 4.2.9-1, using the compliance procedures set forth in the NSPS, 40 CFR 60.48Da. These limits apply to all operations of a CT, that is, periods of startup, shutdown or malfunction are not excluded from the determination of compliance.

iii. NO_x - 0.034 lb/million Btu for syngas (equivalent to 5.0 ppmvd @ 15% O_2) and 0.025 lb/million Btu for natural gas.

This limit shall apply as a 24-hour block average, with compliance determined using continuous monitoring in accordance with Condition 4.2.9-1 using the compliance procedures set forth in the NSPS, 40 CFR 60.48Da. This limit shall not apply during startup, shutdown or malfunction as addressed by Condition 4.2.2(d).

iv. CO - 0.049 lb/million Btu (equivalent to 25.0 ppmvd) for syngas and 0.0450 lb/million Btu (equivalent to 25.0 ppmvd) for natural gas.

These limits shall apply as a 24-hour block average basis, with continuous monitoring conducted in accordance with Condition 4.2.9-1. This limit shall not apply during periods of startup and shutdown of a CT as addressed by Condition 4.2.2(d).

v. Sulfuric Acid Mist - 0.0035 lb/million Btu (equivalent to 0.4 ppmw) for syngas only).

This limit shall apply as a 3-hour block average, with compliance determined by emission testing in accordance with Condition 4.2.7 and equipment operation. This limit shall not apply during startup, shutdown or malfunction as addressed by Condition 4.2.2(d).

c. The syngas used in the CTs shall be processed to meet the following specification:

Sulfur content: 10 ppm by volume (3-hour block average).

d. The Permittee shall use good air pollution control practices to minimize emissions during startup, shutdown and malfunction of a CT as further addressed in Condition 4.2.5, including the following:

i. Use of natural gas during startup;

ii. Operation of the CTs and associated air pollution control equipment in accordance with written operating procedures that include startup, shutdown and malfunction plan(s) (See also Condition 3.3); and

iii. Inspection, maintenance and repair of the CT and associated air pollution control equipment in accordance with written maintenance procedures.

Note: These requirements are applicable for emissions of SO_2 for which the numerical limits in Condition 4.2.2(b) address emissions during startup, shutdown and malfunction, as well as for emissions of PM, NO_x, CO and sulfuric acid mist, for which the numerical limits in Condition 4.2.2(b) do not apply during startup, shutdown and malfunction. For emissions of these other pollutants for which the numerical limits in Condition 4.2.2(b) do not apply during startup, shutdown and malfunction, applicable lbs/hour limits in Condition 4.2.6(a) (Attachment 1, Table 1), do apply during such periods and serve as "secondary limits" for purposes of BACT, with compliance determined based on engineering analysis and calculations.

4.2.3-1 Applicable Federal Emission Standards

a. Each CT is subject to the New Source Performance Standard (NSPS) for Electric Utility Steam Generating Units, 40 CFR 60, Subpart Da and related provisions in Subpart A. The emissions from each CT shall not exceed the following standards pursuant to the NSPS on and after the date the applicable performance test required to be conducted under 40 CFR 60.8 is or should be completed. In the following, "heat input" means heat input to the combustion turbines and "gross energy output" means the electricity produced by the generators powered by the CTs and steam turbine.

i. Opacity: 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity, pursuant to 40 CFR 60.42a(b).

ii. PM [40 CFR 60.42Da]: Either 18 ng/J (0.14 lb/MWh) gross energy output or 6.4 ng/J (0.015 lb/mmBtu) heat input.

iii. SO_2 [40 CFR 60.43Da]: 1.4 lbs/MWh gross energy output on a 30-day rolling average basis.

iv. NO_x [40 CFR 60.44Da]:

A. NO_x emission shall not exceed:

1. 1.0 lb/MWh gross energy output on a 30-day rolling average basis; and

2. 0.50 lb/mmBtu heat input on a 30-day rolling average basis while burning syngas, and 0.20 lb/mmBtu heat input, on a 30-day rolling average basis while combusting natural gas, or

such alternative limit approved by USEPA on a unit-specific basis, to address the firing of both syngas and natural gas by the CTs.

B. The percent NO_x reduction of potential combustion concentration shall be at least 25%, based on a 30-day rolling average basis.

Note: Compliance with Condition 4.2.3-1(a)(iv)(A) constitutes compliance with the requirements of Condition 4.2.3-1(a)(iv)(B). [See 40 CFR 60.48Da(b)]

v. Mercury [40 CFR 60.45Da]: 0.000020 lb/MWh, gross energy output, based on a 12-month rolling average, excluding periods of startup, shutdown and malfunction, as provided by 40 CFR 60.50Da(g).

b. The CTs are subject to the NSPS for Stationary Gas Turbines, 40 CFR 60, Subpart GG and related provisions in Subpart A. The emissions of each CT shall not exceed the following standards pursuant to the NSPS on and after the date on which the performance test required to be conducted under 40 CFR 60.8 is or should be completed:

i. NO_x: The applicable standard pursuant to 40 CFR 60.332 (a)(1).

ii. SO_2: 0.015 percent by volume at 15 percent oxygen and on a dry basis, or alternatively, the CT shall not burn any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw). [40 CFR 60.333(a) and (b)]

Note: 40 CFR 60, Subpart GG, would not apply if the NSPS were revised so that combined cycle CTs at an IGCC plant are not subject to 40 CFR 60, Subpart GG.

c. At all times, the Permittee shall maintain and operate each CT, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions, pursuant to 40 CFR 60.11(d).

4.2.3-2 Applicable State Emission Standards

a. The emission of smoke or other particulate matter from each CT shall not have opacity greater than 30 percent, pursuant to 35 IAC 212.123(a), except as authorized by 35 IAC Part 201 Subpart I.

b. The emissions of SO_2 into the atmosphere from each CT shall not exceed 2000 ppm, pursuant to 35 IAC 214.301.

c. The emissions of mercury from each CT shall comply with applicable requirements of 35 IAC Part 225, Subpart B.

4.2.3-3 Applicability of Other Regulations of Concern

a. Each CT is an affected unit under the Acid Rain Deposition Control Program pursuant to Title IV of the Clean Air Act and is subject to certain control requirements and emissions monitoring requirements pursuant to 40 CFR Parts 72, 73 and 75. (See Condition 5.1)

b. The CTs qualify as Electrical Generating Units (EGU) for purposes of the NO_x and SO_2 Allowance Programs for Electrical Generating Units. As EGU, the Permittee would have to hold allowances for the NO_x and SO_2 emissions of the CTs during each calendar year and seasonal control period (NO_x only).

4.2.4 Non-Applicability of Regulations of Concern

a. The CTs are not subject to 40 CFR 60, Subpart KKKK, the NSPS for Stationary Combustion Turbines, due to the exemption at 40 CFR 60.4310(c), which excludes CTs at IGCC steam generating units that are subject to 40 CFR 60, Subpart Da.

b. This permit is issued based on the CTs not being subject to requirements to monitor opacity under the NSPS or Acid Rain Program because they qualify as gas-fired units for purposes of 40 CFR 60.49Da(a) and 75.14(c).

4.2.5 Operating Requirements

a. The Permittee shall operate each CT and associated air pollution control equipment in accordance with good air pollution control practice to minimize emissions, by operating in accordance with detailed written operating procedures as it is safe to do so. These procedures at a minimum shall:

i. Address startup, normal operation, shutdown and malfunction events.

ii. Fulfill applicable requirements of Condition 3.3 for a Startup, Shutdown and Malfunction Plan, including detailed provisions for review of relevant operating parameters of the CT systems during startup, shutdown and malfunction as necessary to make adjustments and corrections to reduce or eliminate any excess emissions.

iii. With respect to startup, address readily foreseeable startup scenarios, including so called "hot startups" when the operation of a CT is only temporarily interrupted, and provide for appropriate review of the operational condition of a CT prior to initiating startup of the CT.

iv. A. With respect to malfunction, identify and address likely malfunction events with specific programs of corrective actions, and provide that upon occurrence of a malfunction that will result in emissions in excess of the applicable limits in Condition 4.2.2(b) or 4.2.3, the Permittee shall, as soon as practicable, repair the affected equipment, reduce the operating rate of the CT or remove the CT from service so that excess emissions cease.

B. Consistent with the above, if the Permittee has maintained and operated a CT and associated air pollution control equipment so that malfunctions are infrequent, sudden, not caused by poor maintenance or careless operation, and in general are not reasonably preventable, the Permittee shall begin shutdown of the CT within 90 minutes, unless the malfunction is expected to be repaired within 120 minutes or such shutdown could threaten the stability of the regional electrical power supply. In such case, shutdown of the CT shall be undertaken when it is apparent that repair will not be accomplished within 120 minutes or shutdown will not endanger the regional power system. In no case shall shutdown of the CT be delayed solely for the economic benefit of the Permittee.

Note: If the Permittee determines that the continuous emission monitoring system (CEMS) is inaccurately reporting excess emissions, the CT may continue to operate provided the Permittee records the information it is relying upon to conclude that the CT and associated emission control systems are functioning properly and the CEMS is reporting inaccurate data and the Permittee takes prompt action to resolve the accuracy of the CEMS.

b. i. Each CT and its air pollution control systems shall be operated in a manner consistent with good air pollution control practice to minimize emissions during startup and shutdown including the following:

A. Except during startup or shutdown of a CT or for the purpose of emission testing, after a CT begins gainful operation, the Permittee shall minimize operation of the CT below 60 percent load and shall not operate CTs below the lowest load at which emission testing conducted in accordance with Condition 4.2.7 has demonstrated compliance with the applicable hourly emission limits in Table 1;

B. The Permittee shall operate in accordance with written operating procedures that shall include at a minimum the following measures:

1. SCR reagent injection only after the CT operating conditions are appropriate;

2. Review of operating parameters of the CT during startup or shutdown as necessary for proper CT operation with appropriate adjustments to reduce emissions; and

3. Implementation of inspection and repair procedures for a CT prior to attempting an additional startup following repeated trips.

C. The Permittee shall maintain the CTs and associated air pollution control systems in accordance with written procedures that shall include at a minimum the following measures:

1. Periodic inspection of emissions-related components;

2. Timely repair and routine replacement of emissions-related components.

ii. The above procedures may incorporate the manufacturer's written instruction for operation and maintenance of the CTs and associated control systems. The Permittee shall review these procedures at least annually and shall revise or enhance them if necessary to be consistent with good air pollution control practice based on the actual operating experience and performance of the source.

c. The Permittee shall maintain each CT and associated air pollution control equipment in accordance with good air pollution control practice to assure proper functioning of equipment and minimize malfunctions, including maintaining the CT in accordance with written procedures developed for this purpose.

d. The Permittee shall review its operating and maintenance procedures for the CTs as required above on a regular basis and revise them if needed, consistent with good air pollution control practice based on actual operating experience and equipment performance. This review shall occur at least biannually if not otherwise initiated by occurrence of a startup, shutdown, or malfunction event that is not adequately addressed by the existing plans or a specific request by the Illinois EPA for such review.

4.2.6 Emission Limitations

a. Emissions from the CTs shall not exceed the limitations in Attachment 1, Table I.

b. For hourly limitations for which compliance is to be determined on a 24-hour average basis, continuous emission monitoring is required for the pollutant (see Condition 4.2.8-1). Monitoring data shall be compiled on a calendar day basis to determine compliance, except for NO_x and CO for the calendar day in which a startup or shutdown of a CT occurred as addressed by Condition 4.2.5(a) for which monitoring data shall be compiled for the 24-hour period following or preceding such event, as appropriate.

c. For hourly limitations for which compliance is to be determined on a 3-hour average basis, emission testing is required for the pollutant (see Condition 4.2.7). When compliance is determined from such testing, the results of such testing shall be compiled as the average of the individual test runs to determine compliance, as provided by 35 IAC Part 283.

4.2.7 Emission Testing

a. i. A. Within 60 days after achieving the maximum production rate at which a CT will be operated but not later than 180 days after initial startup of each CT, the Permittee shall have tests conducted for opacity and emissions of NO_x, CO, PM (filterable and condensable), VOM, SO_2, hydrogen chloride*, hydrogen fluoride*, sulfuric acid mist*, and mercury* and other metals* as follows at its expense by an approved testing service while the CT is operating at maximum operating load and other representative operating conditions, including firing of syngas only. The Permittee may set forth a strategy for performing emission testing in the normal load range of the CTs. In addition, the Permittee may also perform measurements to evaluate emissions at other load and operating conditions.)

* Testing for these pollutants only required for firing of syngas.

B. This period of time may be extended by the Illinois EPA for up to an additional 365 days upon written request by the Permittee as needed to reasonably accommodate unforeseen difficulties in the startup and testing of the CTs, provided that initial performance testing required by the NSPS, 40 CFR 60.8, has been completed for the CT and the test report submitted to the Illinois EPA.

ii. Between 21 and 27 months after performance of the initial testing that demonstrates compliance with applicable requirements, the Permittee shall have the emissions of PM, VOM, sulfuric acid mist, and any other pollutants specified by the Illinois EPA from each affected CT retested as specified above, while firing syngas.

iii. The Permittee shall perform emission tests as provided below as requested by the Illinois EPA for a CT within 45 days of a written request by the Illinois EPA or such later date agreed to by the Illinois EPA.

Note: Further requirements for periodic emission testing may be established in the CAAPP Permit for the plant.

b. i. For purposes of other emission testing, the following methods and procedures in 40 CFR 60.50Da and 60.335 shall be used for testing, unless other methods adopted by or being developed by USEPA are specified or approved by the Illinois EPA.

Opacity	Method 9
Location of Sample Points	Method 1
Gas Flow and Velocity	Method 2
Flue Gas Weight	Method 3 or 3A
Moisture	Method 4
Particulate Matter	Method 5, or Method 201[1], or 201A (40 CFR 51, Appendix M), with Method 19 as specified in 40 CFR 60.48a(b) and Method 202[2]
Nitrogen Oxides[3]	Method 19, as specified in 40 CFR 60.48a(d)
Sulfur Dioxides[3]	Method 19, as specified in 40 CFR 60.48a(c)
Carbon Monoxide[3]	Method 10
Volatile Organic Material[4]	Method 18 and 25A
Hydrogen Chloride[6]	Method 26
Hydrogen Fluoride[6]	Method 26
Sulfuric Acid Mist[6]	Method 8[2]
Metals[5, 6]	Method 29

Notes:

1 The Permittee may report all PM emissions measured by USEPA Method 5 as PM_{10}, in which case separate testing using USEPA Method 201 or 201A need not be performed.

2 Notwithstanding the general requirement to use USEPA test methods, appropriate refinements or adaptations shall be made to the USEPA test methods or other established test methods may be used for testing, subject to review and approval by the Illinois EPA to facilitate accurate and reliable measurements given the composition of the exhaust. In particular, adaptations shall be made to USEPA Method 202, to prevent positive bias from conversion of sulfur dioxide to sulfuric acid in the impingers, for example by additional purges or separate, simultaneous measurements of the sulfuric acid emissions.

3 Emission testing shall be conducted for purposes of certification of the continuous emission monitors required by Condition 4.2.8-1. Thereafter, the NO_x,

SO_2 and CO emission data from certified monitors may be provided in lieu of conducting emissions tests.

[4] The Permittee may exclude methane, ethane and other exempt compounds from the results of any VOM test provided that the test protocol to quantify and correct for any such compounds is included in the test plan approved by the Illinois EPA.

[5] For purposes of this permit, metals are defined as mercury, arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel.

[6] As an alternative to emission testing, with approval by the Illinois EPA, the Permittee may determine emissions by sampling and elemental analysis of the fuel, assuming that all material in the fuel is emitted, with appropriate conversion factors applied, e.g., all fluorine is emitted as hydrogen fluoride.

ii. For purposes of testing for the NSPS the methods and procedures in 40 CFR 60.50Da and 60.335 shall be used.

c. i. Test plans, test notifications, and test reports shall be submitted to the Illinois EPA in accordance with Condition 6.2. In addition to other required information, if test runs that are longer than one-hour in duration are planned, the expected duration of the runs and the reason for extended runs shall be explained.

ii. In addition to other information required in a test report, test reports shall include detailed information on the operating conditions of a CT during testing, including:

A. Feedstock and fuel (syngas) consumption (in tons and mmscf, respectively);

B. Composition of fuel (Refer to Condition 4.2.10(b)), including the metals, chlorine and fluorine content, expressed in pound per million Btu;

C. Firing rate (million Btu/hour) and other significant operating parameters of the CT;

D. Control device operating rates or parameters;

E. Opacity of the exhaust from the CT, 6-minute averages and 1-hour averages; and

F. Turbine/Generator output rate (MW_e gross).

4.2.8-1 Emissions Monitoring - SO_2, NO_x, and CO

a. i. The Permittee shall install, certify, operate, calibrate, and maintain continuous monitoring systems on each CT for emissions of SO_2, NO_x and CO, and either oxygen or carbon dioxide in the exhaust.

ii. The Permittee shall also operate and maintain these emissions monitoring systems according to site-specific monitoring plan(s), which shall be submitted at least 60 days before the initial startup of a CT to the Illinois EPA for its review and comment. With this submission, the Permittee shall submit the proposed type of monitoring equipment and proposed sampling location(s), which shall be approved by the Illinois EPA prior to installation of equipment.

iii. The Permittee shall fulfill all applicable requirements for monitoring in the NSPS, 40 CFR 60.13, 60.49Da, 60.334 and 40 CFR 60 Appendix B, and the federal Acid Rain Program, 40 CFR Part 75, as appropriate. These rules require that the Permittee maintain detailed records for both the measurements made by these systems and the maintenance, calibration and operational activity associated with the monitoring systems.

iv. In addition, pursuant to the NSPS, when NO_x or SO_2 emission data are not obtained from a continuous monitoring system because of system breakdowns, repairs, calibration checks and zero span adjustments, emission data shall be obtained by using standby monitoring systems, emission testing using USEPA Reference Methods to provide emission data for a minimum of 90 percent of all operating hours in a CT operating day, in at least 27 out of 30 successive CT operating days, as required by 40 CFR 60.49Da(e).

Note: Fulfillment of the above criteria for availability of emission data from a monitoring system does not shield the Permittee from potential enforcement for failure to properly maintain and operate the system.

b. Notwithstanding the above, the Permittee may conduct monitoring for emissions of SO_2 from the CTs using an alternative monitoring methodology, e.g., using the Optional SO_2 Emission Data Protocol for Gas-Fired and Oil-Fired Unit, 40 CFR Part 75, Appendix D, if USEPA formally approves use of an alternative monitoring methodology for the CTs as provided for by 40 CFR 60.13(i) or 40 CFR 75, Subpart E.

4.2.8-2 Emissions Monitoring - Mercury

a. Pursuant to 40 CFR 60.49Da(p) through (s), as applicable, the Permittee shall install, operate and maintain a continuous or semi-continuous monitoring system to measure the mercury emissions of each CT using monitoring methodology and procedures specified by USEPA for monitoring of mercury emissions units, including 40 CFR 60.49Da(p) and 40 CFR Part 75, Subpart I.

b. Notwithstanding the above, the Permittee may conduct monitoring for emissions of mercury from the CTs using an alternative monitoring methodology, e.g., monitoring the mercury content of the fuel supply to the CTs, if USEPA formally approves use of an alternative monitoring methodology for the CTs, as provided for by 40 CFR 60.13(i) and 40 CFR 75.80(h).

c. The Permittee shall fulfill all applicable monitoring requirements of 35 IAC Part 225, Subpart B.

d. The Permittee shall keep logs for the operation, calibration and maintenance of these monitoring systems.

4.2.9-1 Fuel Sampling and Analysis

a. The Permittee shall monitor sulfur content of the gas fired in the CTs pursuant to the applicable provisions in 40 CFR Part 75, Appendix D, for natural gas combustion.

b. The Permittee shall also sample and analyze for the sulfur and nitrogen content on the natural gas being fired in the CTs in accordance with 40 CFR 60.334(h) unless alternative provisions are approved by USEPA in accordance with 40 CFR 60.334(h), in which case the Permittee shall comply with such alternative provisions.

c. The Permittee shall conduct sampling and analysis of the coal supply to the gasifiers for mercury content in accordance with the requirements of 35 IAC Part 25, Subpart B, if applicable.

4.2.9-2 Operational Monitoring and Measurements

a. The Permittee shall install, evaluate, operate, and maintain meters to measure and record consumption of syngas and natural gas by each CT.

b. The Permittee shall equip, operate, and maintain each CT with other instrumentation to measure relevant operating parameters for the CTs and associated control systems to enable effective control of emissions, including parameters such as ambient temperature, inlet air temperature, CT firing rate, nitrogen diluent injection rate, SCR reagent injection rate, and flue gas temperature at the SCR catalyst.

c. The Permittee shall maintain the records of the measurements made by these systems and records of maintenance and operational activity associated with the systems.

d. If the Permittee complies with 35 IAC Part 225, Subpart B by means of 35 IAC 225.237(a)(i)(A), the Permittee shall monitor the gross electrical output of the generators associated with each CT/HRSG in accordance with 35 IAC 225.263.

4.2.10 Recordkeeping

a. The Permittee shall maintain the following records:

i. Records of the heat content of the natural gas (Btu/ft^3) being fired, with supporting documentation, on a quarterly basis;

ii. Records of the amount of fuel (syngas) combusted in each CT as specified in 40 CFR Part 60, Appendix A, Method 19.

iii. Records of the sulfur content of the fuel used in the CTs as determined in accordance with Condition 4.2.9-1;

iv. Copies of opacity determinations made for the CTs on the behalf of the Permittee by qualified observer(s) using Method 9;

v. A copy of the Final Report(s) for emission testing conducted pursuant to Condition 4.2.7;

vi. Records of all information needed to demonstrate compliance with the NSPS, including performance tests, monitoring data, fuel analysis, and calculations, consistent with the requirements of 40 CFR 60.7(f).

vii. Records of all information as required by applicable recordkeeping provisions of 35 IAC Part 225, Subpart B.

b. The Permittee shall maintain the following records with respect to operation and maintenance of each CT and associated control equipment:

i. An operating log for each CT that at a minimum shall address:

A. Each startup of the CT, including the date and time, description, if written procedures were not followed, nature of the startup, sequence and timing of major steps in the startup, any unusual occurrences during the startup, and any deviations from the established startup procedures, with explanation;

B. Each shutdown of the CT, including the date and time, description, if written procedures were not followed, the nature and reason for the shutdown, sequence and timing of major steps in the shutdown, any unusual occurrences during the shutdown, and any deviations from the established shutdown procedures, with explanation; and

C. Each malfunction or breakdown of the CT, that significantly impaired emission performance, including the nature and duration of the event, sequence and timing of major steps in the event, corrective actions taken, any deviations from the established procedures for such an event, and preventative actions taken to address similar events.

ii. Inspection, maintenance and repair log(s) for each CT and associated control system that at a minimum shall identify dates and nature of activities performed, those such activities that are performed related to components that may affect emissions; the reason for such activities, i.e., whether planned or initiated due to a specific event or condition; and any failure to carry out the established maintenance procedures, with explanation;

iii. Fuel consumption, operating hours and number of startups for each turbine, compiled on a monthly basis;

iv. Consumption of SCR reagent, as determined from inventory record, compiled on at least a monthly basis; and

v. Copies of the steam charts and daily records of steam and electricity generation.

c. Pursuant to 40 CFR 60.48Da(l), the Permittee shall calculate and record the mercury emission rate (lbs/MWh) for each calendar month of the year, using mercury concentrations measured according to the provisions of 40 CFR 60.49Da(p) in conjunction with hourly stack gas volumetric flow rates measured according to the provisions of 40 CFR 60.49Da(l) or (m), and hourly gross electrical outputs, determined according to the provisions in 40 CFR 60.45Da(k), or other alternative monitoring methodology approved by USEPA.

d. The Permittee shall record the following information for any period during which a CT deviated from an applicable requirement:

i. Each period during which a CT exceeded the requirements of this permit, including applicable emission limits, such records shall include at least the information specified by Condition 6.3.

ii. Each period during which opacity of a CT exceeded the level of opacity at which emission testing has demonstrated that the CT would comply with particulate matter emission limits.

e. For each CT, the Permittee shall maintain records of the following items related to emissions:

i. Daily emissions of NO_x, CO, and SO_2 from each CT, based on CEMS data;

ii. For these pollutants, for which CEMS are used, the emissions of the pollutant from each CT recorded hourly (in lbs/mmBtu and lb or ton) by combining the pollutant concentration (in ppm) and diluent concentration (in percent O_2 or CO_2) measurements according to the procedures in 40 CFR 75 Appendix F;

iii. Records of emissions of PM, VOM, fluorides and other pollutants from each CT, based on fuel usage and other operating data for the CT and appropriate emission factors, with supporting documentation; and

iv. Total daily, monthly and annual emissions of NO_x, CO, VOM, PM and SO_2 from the CTs, which shall be compiled on at least a monthly basis.

f. The Permittee shall maintain detailed records related to continued operation of a CT with elevated or above normal emissions due to malfunction or breakdown, including the following:

i. The following detailed information for each period of elevated NO_x emissions accompanying malfunction or breakdown of the SCR system:

A. Date, time and duration of elevated NO_x emissions;

B. Identification of the affected turbine, the NO_x emission rate, the operating condition of the CT, and possible causes for elevated NO_x emissions, e.g., interruption or reduction in SCR reagent flow;

C. A description of corrective actions taken by the Permittee to return NO_x emissions to its permitted limit;

D. If corrective actions did not promptly return NO_x emissions to acceptable levels, the time that the Permittee initiated shutdown of the CT and, if not immediate, a description of the circumstances that made immediate shutdown unsound and a demonstration that shutdown was deferred only until it became safe to do so, with supporting documentation; and

E. A description of further investigation and corrective actions taken by the Permittee following shutdown of the CT prior to returning the affected CT to service.

ii. Hours of operation for each CT, excluding startup and shutdown (hours/month, hours/year);

iii. Hours of elevated NO_x emissions for each CT, excluding startup and shutdown (hours/month, hours/year);

iv. Whether the SCR system was available for 90 and 95 percent of the operating time of the CT in the previous month and year, respectively;

v. Whether the catalyst was spent (i.e., no longer usable);

vi. If the above criteria are not met, an explanation whether the SCR system was properly maintained; and

vii. The following information for each period of above normal opacity:

A. Date, time and duration of observed opacity above normal;

B. Name and position of observer;

C. Identification of the affected CT, a description of the observed opacity, the operating condition of the CT, and possible causes for above normal opacity, e.g., excess natural gas pressure or low natural gas temperature;

D. Whether exceedances of Condition 4.2.3-1 [20 percent opacity] may have occurred, including any Method 9 readings taken by a qualified observer;

E. A description of corrective actions taken by the Permittee to restore normal opacity levels;

F. If corrective actions did not promptly restore acceptable opacity levels, the time that the Permittee initiated shutdown of the turbine and, if not immediate, a description of the circumstances that made immediate shutdown unsound and a demonstration that shutdown was deferred only until it became safe to so, with supporting documentation; and

G. A description of further investigation and corrective actions taken by the Permittee following shutdown of the turbine prior to returning the affected turbine to service.

g. The Permittee shall maintain records that identify:

i. Each period during which a continuous monitoring system was not operational, with explanation;

ii. Each day in which emissions or opacity exceeded an applicable standard or limit; and

iii. Each day in which a turbine did not comply with other applicable requirements.

h. The Permittee shall maintain records documenting its annual review of its operating and maintenance procedures.

i. All records and logs required by this permit shall be retained at a readily accessible location at the source for at least five years from the date of entry and shall be available for inspection and copying by the Illinois EPA upon request. Any record retained in an electronic format (e.g., computer) shall be capable of being retrieved and printed on paper during normal source office hours so as to be able to respond to an Illinois EPA request for records during the course of an on-site inspection.

4.2.11 Notifications

a. Pursuant to 40 CFR 60.52Da, the Permittee shall perform all notifications in accordance with 40 CFR 60.7(a).

b. The Permittee shall notify the Illinois EPA within 30 days of deviations from applicable requirements that are not addressed by the regular reporting required below. These notifications shall include the information specified by Condition 6.5.

c. The Permittee shall submit all notifications required by applicable provisions of 35 IAC Part 225, Subpart B.

4.2.12 Reporting

a. The Permittee shall fulfill applicable reporting requirements in the NSPS, 40 CFR 60.7(c), and 60.51Da, for each CT. For this purpose, quarterly reports shall be submitted to the Illinois EPA no later than 30 days after the end of each calendar quarter.

b. i. Either as part of the periodic NSPS report or accompanying such report, the Permittee shall report to the Illinois EPA any and all opacity and emission measurements for a CT that are in excess of the respective requirements set by this permit. These reports shall provide for each such incident, the pollutant emission rate, the date and duration of the incident, and whether it occurred during startup, malfunction, breakdown, or shutdown. If an incident occurred during malfunction or breakdown, the corrective actions and actions taken to prevent or minimize future reoccurrences shall also be reported.

ii. These reports shall also be submitted for each occurrence of elevated emissions from a CT due to malfunction or breakdown, as addressed by the records required by Condition 4.2.10, when corrective actions did not promptly restore acceptable emission levels and the shutdown of the CT was not then immediately initiated but was deferred. This report shall include a copy of the relevant records and additional explanation by the Permittee. This report shall be submitted within 30 days of the event.

iii. These reports shall also address any deviations from applicable compliance procedures for a CT established by this permit, including specifying periods during which the continuous monitoring systems were not in operation.

c. The Permittee shall submit all reports required by applicable provisions of 35 IAC Part 225, Subpart B.

d. In conjunction with the Annual Emission Report required by 35 IAC Part 254, the Permittee shall provide:

The operating hours of each turbine; the percentage of operation at different ambient temperature ranges; the total number of startups; and the total fuel consumption during the preceding calendar year.

e. The Permittee shall comply with applicable reporting requirements under the Acid Rain Program, with a single copy of such report sent to Illinois EPA, Division of Air Pollution Control Compliance Section.

f. The Permittee shall submit an exceedance report to the Illinois EPA if there is any exceedance of the requirements of Condition 4.2.6 of this permit, as determined by the records required by this permit or by other means. This report shall include the amount of emissions released in accordance with the recordkeeping requirements, a copy of the relevant records, and a description of the exceedance or violation and efforts to reduce emissions and future occurrences.

i. Any exceedance of NO_x, SO_2 or CO emission limits shall be reported with the quarterly report required by the federal NSPS and Acid Rain Program; and

ii. Any other exceedance of applicable requirements shall be reported within 30 days of the event.

CONDITION 4.3: UNIT-SPECIFIC CONDITIONS FOR COAL AND OTHER BULK MATERIAL HANDLING, STORAGE, PROCESSING AND LOADOUT OPERATIONS

4.3.1 Description of Emission Units

The affected units for the purpose of these unit-specific conditions are equipment and facilities handling coal and other bulk materials (e.g., slag from the gasifiers) that are involved with the operation of the plant and that have the potential for particulate matter (PM) emissions. Affected units include receiving, transfer, storage, preparation (crushing, screening, etc.) and loading operations, as relevant for particular materials, for these materials.

Emissions of PM from affected units must be controlled by appropriate measures given the nature of the material. In particular, units handling dry materials must be enclosed and aspirated to control equipment if it is practical to do so. For receiving of coal and storage of coal, for which total enclosure is not practicable, measures must be used to very effectively reduce the generation of emissions.

4.3.2 Control Technology Determination

a. PM emissions from an affected unit handling a wet material shall be controlled by the following measures. For this purpose, wet material is a material that has sufficient moisture during normal operation to minimize the potential for direct emissions.

   i. Maintaining the material with adequate moisture to prevent visible emissions directly from such unit during the handling, storage or load out of the material.

   ii. Collection of spilled material that could become airborne if it dried or were subject to vehicle traffic as part of the Program for Control of Fugitive Dust required by Condition 4.6.5(a).

b. PM emissions from an affected unit handling a dry material, other than a storage pile for dry material and handling operations associated with the storage pile, shall be controlled by:

   i. Enclosure of the unit so as to prevent visible fugitive emissions, as defined by 40 CFR 60.671, from the affected unit.

   ii. Aspiration to a control device designed to emit no more than 0.01 grains/dry standard cubic foot (gr/dscf), which device shall be operated in accordance with good air pollution control practice to minimize emissions. For this purpose, the control device shall be a baghouse or other filtration type device unless the Permittee demonstrates and the Illinois EPA concurs that another type of control device is preferable due to considerations of operational safety.

c. PM emissions from storage piles for dry material, including material handling operations associated with the piles, shall be controlled by application of water or other dust suppressants so as to minimize fugitive emissions to the extent practicable. For this purpose, there shall either:

   i. Be no visible emissions from the affected unit, as determined in accordance with USEPA Method 22, or

   ii. A nominal control efficiency of 90 percent shall be achieved from the uncontrolled emission rate, as follows, as determined using appropriate USEPA emission factors for particulate emissions from handling of a material dry, in the absence of any control of emissions, and engineering analysis and calculations for the control measures that are actually present:

4.3.3-1 Applicable Federal Emission Standards

a. Affected units engaged in handling and processing coal shall comply with applicable requirements of the NSPS for coal Preparation Plants, 40 CFR 60, Subpart Y, and related provisions of 40 CFR 60, Subpart A.

b. Pursuant to the NSPS, the opacity of the exhaust from coal processing and conveying equipment, coal storage systems (other than open storage piles), and coal loading systems shall not exceed 20 percent. [40 CFR 60.252(c)]

c. At all times, the Permittee shall maintain and operate affected units that are subject to NSPS, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions, pursuant to 40 CFR 60.11(d).

4.3.3-2 Applicable State Emission Standards

a. The emission of smoke or other PM from affected units shall not have an opacity greater than 30 percent, except as allowed by 35 IAC 212.124. Compliance with this limit shall be determined by 6-minute averages of opacity measurements in accordance with USEPA Reference Method 9. [35 IAC 212.109 and 212.123(a)]

b. With respect to emissions of fugitive PM, affected units shall comply with 35 IAC 212.301, which provides that emissions of fugitive PM shall not be visible from any process, including any material handling or storage activity, when looking generally toward the zenith at a point beyond the property line of the source, except when the wind speed exceeds 25 miles per hour, as provided by 35 IAC 212.314.

c. The emissions of PM from affected units other than units excluded by 35 IAC 212.323 (refer to Condition 4.3.5(b)) shall comply with the applicable limit pursuant to 35 IAC 212.321, which rule limits emissions based on the process weight rate of emission units and allows a minimum emission rate of 0.55 lbs/hour for any individual unit.

4.3.4 Non-Applicability of Regulations of Possible Concern

This permit is issued based on the storage piles and associated operations and the coal handling operations not being subject to 35 IAC 212.321 pursuant to 35 IAC 212.323, which provides that 35 IAC 212.321 shall not apply to emission units, such as stock piles, to which, because of the disperse nature of such emission units, such rules cannot reasonably be applied.

4.3.5 Operating Requirements

a. i. Bulk materials other than coal or slag that have the potential for PM emissions shall be stored in silos, bins, and buildings, without storage of such materials in outdoor piles except on a temporary basis during breakdown or other disruption in the capabilities of the enclosed storage facilities.

ii. Coal storage piles and temporary piles for other materials shall be equipped and operated with adjustable stacker(s), rotary stacker(s), coal ladders or other comparable devices to minimize the distance that material drops when added to the pile and minimize the associated PM emissions.

b. i. The Permittee shall implement and maintain control measures for the affected units that minimize visible emissions of PM and provide assurance of compliance with the applicable limits and standards in Conditions 4.3.2, 4.3.3-1 and 4.3.3-2.

ii. For this purpose, storage piles and associated material handling operations shall be addressed by and controlled in accordance with the control plan for fugitive particulate matter emissions required by Condition 4.6.5(a).

c. The affected units, including associated control equipment, shall be operated and maintained in accordance with good air pollution control practice to minimize emissions.

4.3.6 Emission Limitations

Annual emissions of PM from the affected units shall not exceed 0.84 tons/year. Compliance with this annual emission limit shall be determined from a rolling total of 12 months of emission data, calculated from the material handled and other, operating information for affected units, and appropriate emission factors.

4.3.7-1 Initial Performance Testing

a. Within 60 days after achieving the maximum production rate at which each affected unit subject to NSPS will be operated, but not later than 180 days after initial startup of each such unit, the Permittee shall have emissions tests conducted at its expense as follows by an approved testing service to demonstrate compliance with applicable NSPS limits under unit operating conditions that are representative of maximum emissions.

b. The following USEPA methods and procedures shall be used for PM and opacity measurements as specified in 40 CFR 60.254:

PM - Method 5, with the sampling time and sample volume for each run to be at least 60 minutes and 30 dscf and sampling to begin no less than 30 minutes after startup and to terminate before shutdown begins.

Opacity - Method 9, with measurements performed by a certified observer.

c. Test plan(s), test notifications, and test reports shall be submitted to the Illinois EPA in accordance with Condition 3.2.

4.3.7-2 Periodic Testing

a. i. The Permittee shall have the opacity of the emissions of the affected units during representative weather and operating conditions determined by a qualified observer in accordance with USEPA Test Method 9, as further specified below.

A. If emissions are normally visible from a unit when it is in operation, as determined by USEPA Reference Method 22, opacity testing shall be conducted at least annually.

B. Upon written request by the Illinois EPA, such testing shall be conducted for specific affected units within 45 calendar days of the request or on the date agreed upon by the Illinois EPA, whichever is later.

ii. The duration of opacity observations for each test shall be at least 30 minutes (five 6-minute averages) unless the average opacities for the first 12 minutes of observations (two six-minute averages) are both less than 5.0 percent.

iii. A. The Permittee shall notify the Illinois EPA at least 7 days in advance of the date and time of these tests, in order to allow the Illinois EPA to witness testing. This notification shall include the name and employer of the qualified observer(s).

B. The Permittee shall promptly notify the Illinois EPA of any changes in the time or date for testing.

iv. The Permittee shall provide a copy of its observer's readings to the Illinois EPA at the time of testing, if Illinois EPA personnel are present.

v. The Permittee shall submit a written report for this testing within 15 days of the date of testing. This report shall include:

A. Date and time of testing.

B. Name and employer of qualified observer.

C. Copy of current certification.

D. Description of observation conditions, including recent weather.

E. Description of the operating conditions of the affected processes.

F. Raw data.

G. Opacity determinations.

H. Conclusions.

b. Unless otherwise specified for the affected units by the source's CAAPP permit:

i. Within 90 days of a written request from the Illinois EPA, the Permittee shall have the PM emissions at the stacks or vents of affected units, as specified in such request, measured during representative operating conditions, as set forth below.

ii. A. Testing shall be conducted using appropriate USEPA Test Methods, including Method 5 or 17 for PM emissions.

B. Compliance may be determined from the average of three valid test runs, subject to the limitations and conditions contained in 35 IAC Part 283.

iii. The Permittee shall submit a test plan to the Illinois EPA at least 60 days prior to testing, which plan shall include the information for test plans specified by General Condition 6.2(a).

iv. The Illinois EPA shall be notified prior to these tests to enable the Illinois EPA to observe these tests. Notification of the expected date of testing shall be submitted a minimum of 30 days prior to the expected date. Notification of the actual date and expected time of testing shall be submitted a minimum of 5 working days prior to the actual date of the test. The Illinois EPA may, at its discretion, accept notification with shorter advance notice provided that the Illinois EPA will not accept such notification if it interferes with the Illinois EPA's ability to observe the testing.

v. The Permittee shall expeditiously submit Final Report(s) for required emission testing to the Illinois EPA, no later than 90 days after the date of testing. These reports shall include the information specified in Condition 6.2(c) and the following information:

A. A summary of results.

B. Detailed description of test method(s), including description of sampling points, sampling train, analysis equipment, and test schedule.

C. Detailed description of the operating conditions of the affected process during testing, including operating rate (tons/hour) and the control measures being used.

D. Detailed data and calculations, including copies of all raw data sheets and records of laboratory analyses, sample calculations, and data on equipment calibration.

E. Representative opacity data (6-minute average) measured during testing.

4.3.8 Operational Instrumentation

a. The Permittee shall install, operate and maintain systems to measure the pressure drop across each baghouse used to control affected units, other than bin vent filters and other similar filtration devices.

b. The Permittee shall maintain the records of the measurements made by these systems and records of maintenance and operational activity associated with the systems.

4.3.9 Inspections

a. i. The Permittee shall conduct inspections of affected units on at least a monthly basis with personnel who are not directly responsible for the day-to-day operation of these units, for the specific purpose of verifying that the measures identified in the operating program and other measures required to control emissions from affected units are being properly implemented.

ii. These inspections shall include observation for the presence of visible emissions, performed in accordance with USEPA Method 22, from buildings in which affected units are located and from units from which the Permittee has elected to demonstrate no visible emissions.

b. The Permittee shall perform detailed inspections of the dust collection equipment for affected units while the units are out of service, with an initial inspection performed before any maintenance and repair activities are conducted during the period the unit is out of service and a follow-up inspection performed after any such activities are completed. These inspections shall be conducted at least every 15 months.

4.3.10 Recordkeeping

a. For affected units that are subject to NSPS, the Permittee shall fulfill applicable recordkeeping requirements of the NSPS, 40 CFR 60.7.

b. The Permittee shall maintain file(s), which shall be kept current, that contain:

i. The maximum operating capacity of each affected unit or group of related units (tons/hour).

ii. A. For the baghouses and other filter devices associated with affected units, design specifications for each device (type of unit, maximum design exhaust flow (acfm and scfm), filter area, type of filter cleaning, performance guarantee for particulate exhaust loading in gr/scf, etc.), the manufacturer's recommended operating and maintenance procedures for the device, and design specification for the filter material in each device (type of material, surface treatment(s) applied to material, weight, performance guarantee, warranty provisions, etc.).

B. For each baghouse, the normal range of pressure drop across the device and the minimum and maximum safe pressure drop for the device, with supporting documentation.

iii. For affected units that are not controlled with baghouses or other filter-type devices, a detailed description of the work practices used to control emissions of PM pursuant to Condition 4.3.5(b). These control measures are referred to as the "established control measures" in this subsection of this permit.

iv. The designated PM emission rate, in pounds/hour and tons/year, from affected units, either individually or grouped by related units, with supporting calculations and documentation, including detailed documentation for the level of emissions control achieved through the work practices that are used to control PM emissions. For each category of affected unit (e.g., coal handling), the sum of these emission rates shall not exceed the totals in Table 2 for the category of affected unit. (See also Condition 4.3.7.)

v. A demonstration that confirms that the above established control measures are sufficient to assure compliance with the above emissions rates and, for units to which it applies, Condition 4.3.3-2(c), at the maximum process weight rate at which each affected unit can be operated (tons/hour), with supporting emission calculations and documentation for the emission factors and the efficiency of the control measures being relied upon by the Permittee. Except as addressed by Condition 4.3.10(b)(ii) or testing of PM emissions from an affected unit is conducted in accordance with Condition 4.3.7-2, this demonstration shall be developed using emission factors for uncontrolled PM emissions, efficiency of control measures, and controlled PM emissions published by USEPA.

c. The Permittee shall keep records for the amount of bulk materials received by or loaded out from the plant by category or type of material (tons/month).

d. i. The Permittee shall keep inspection and maintenance log(s) or other records for the control measures associated with the affected units, including buildings and enclosures, dust suppression systems and control devices.

ii. These records shall include the following information for the inspections required by Condition 4.3.9(a):

A. Date and time the inspection was performed and name(s) of inspection personnel.

B. The observed condition of the control measures for each affected unit, including the presence of any visible emissions.

C. A description of any maintenance or repair associated with established control measures that are recommended as a result of the inspection and a review of outstanding recommendations for maintenance or repair from previous inspection(s), i.e., whether recommended action has been taken, is yet to be performed or no longer appears to be required.

D. A summary of the observed implementation or status of actual control measures, as compared to the established control measures.

iii. These records shall include the following information for the inspections required by Condition 4.3.9(b):

A. Date and time the inspection was performed and name(s) of inspection personnel.

B. The observed condition of the dust collection equipment.

C. A summary of the maintenance and repair that is to be or was conducted on the equipment.

D. A description of any maintenance or repair that is recommended as a result of the inspection and a review of outstanding recommendations for maintenance or repair from previous inspection(s), i.e., whether recommended action has been taken, is yet to be performed or no longer appears to be required.

E. A summary of the observed condition of the equipment as related to its ability to reliably and effectively control emissions.

e. The Permittee shall maintain records of the following for each incident when any affected unit operated without the control measures required by Condition 4.3.2 or 4.3.5(b) or (c):

i. The date of the incident and identification of the unit(s) that were involved.

ii. A description of the incident, including: the established control measures that were not present or implemented; the established control measures that were present, if any; and other control measures or mitigation measures that were implemented, if any.

iii. The time at and means by which the incident was identified, e.g., scheduled inspection or observation by operating personnel.

iv. Operational data for the incident, e.g., the measured pressure drop of a baghouse, if the pressure drop of the baghouse, as measured pursuant to Condition 4.3.8, deviated outside the levels set as good air pollution control practices.

v. The corrective action(s) taken and the length of time after the incident was identified that the unit(s) continued to operate before established control measures were in place or the operations were shutdown (to resume operation only after established control measures were in place) and, if this time was more than one hour, an explanation why this time was not shorter, including a detailed description of any mitigation measures that were implemented during the incident.

vi. The estimated total duration of the incident, i.e., the total length of time that the unit(s) ran without established control measures and the estimated amount of material processed during the incident.

vii. A discussion of the probable cause of the incident and any preventative measures taken.

viii. An estimate of any additional emissions of PM (pounds) above the PM emissions associated with normal operation that resulted from the incident, if any, with supporting calculations.

ix. A discussion whether any applicable emission standard, as listed in Condition 4.3.2, 4.3.3-1, or 4.3.3-2 or any applicable emission rate, as identified in the records pursuant to Condition 4.3.10(b), may have been violated during the incident, with an estimate of the amount of any excess PM emissions (lbs) and supporting explanation.

f. The Permittee shall maintain the following records for the emissions of the affected units:

i. A file containing the standard emission factors used by the Permittee to determine PM emissions from the units, with supporting documentation.

ii. Records of PM emissions based on operating data for the unit(s) and appropriate emission factors, with supporting documentation and calculations.

g. The Permittee shall keep records for all opacity measurements made in accordance with USEPA Method 9 for affected units that it conducts or that are conducted at its behest by individuals who are qualified to make such observations. For each occasion on which such measurements are made, these records shall include the formal report for the measurements if conducted pursuant to Condition 4.3.7 or otherwise the identity of the observer, a description of the measurements that were made, the operating condition of the affected unit, the observed opacity, and copies of the raw data sheets for the measurements.

4.3.11 Notifications

The Permittee shall notify the Illinois EPA within 30 days of deviations from applicable emission standards or operating requirements for the affected units that continue* for more than 24 hours. These notifications shall include the information specified by Condition 6.5.

* For this purpose, time shall be measured from the start of a particular event. The absence of a deviation for a short period shall not be considered to end the event if the deviation resumes. In such circumstances, the event shall be considered to continue until corrective actions are taken so that the deviation ceases or the Permittee takes the affected unit out of service for repairs.

4.3.12 Reporting Requirements

a. The Permittee shall submit quarterly reports to the Illinois EPA for all deviations from emission standards, including standards for visible emissions and opacity, and operating requirements set by this permit. These notifications shall include the information specified by Condition 6.5.

b. These reports shall also address any deviations from applicable compliance procedures established by this permit for affected units.

4.3.13 Operational Flexibility

The Permittee is authorized, as follows, to construct and operate affected units that differ from those described in the application in certain respects without obtaining further approval by the Illinois EPA. This condition does not affect the Permittee's obligation to comply with all applicable requirements for affected units:

a. This authorization only extends to changes that result from the detailed design of the project and any refinements to that design of the affected units that occur during construction and the initial operation of the plant.

b. With respect to air quality impacts, these changes shall generally act to improve dispersion and reduce impacts, as emissions from individual units are lowered, units are moved apart or away from the fence line, stack heights are increased, and heights of nearby structures are reduced.

c. The Permittee shall notify the Illinois EPA prior to proceeding with any changes. In this notification, the Permittee shall describe the proposed changes and explain why the proposed changes will act to reduce impacts, with detailed supporting documentation.

d. Upon written request by the Illinois EPA, the Permittee shall promptly have air quality dispersion modeling performed to demonstrate that the overall effect of the changes is to reduce air quality impacts, so that impacts from affected units remain at or below those predicted by the air quality analysis accompanying the application.

CONDITION 4.4: UNIT-SPECIFIC CONDITIONS FOR THE COOLING TOWER

4.4.1 Description of Emission Unit

The affected unit for the purpose of this unit-specific condition is a cooling tower, which supplies cooling water to the gasification block, air separation unit, and power block.

The cooling tower is a source of particulate matter (PM) because of mineral material present in the water, which is emitted to the atmosphere due to water droplets that escape from the cooling tower or completely evaporate. The emissions of PM are controlled by drift eliminators, which collect water droplets entrained in the air exhausted from the cooling tower.

4.4.2 Control Technology Determination

a. The affected unit shall be equipped, operated, and maintained with drift eliminators designed to limit the loss of water droplets from the unit to not more than 0.0005 percent of the circulating water flow.

b. The emissions of particulate matter from the affected unit shall not exceed 1.44 pounds of PM_{10} per hour, as determined from relevant operating data for the cooling tower and the efficiency of the drift eliminators, using engineering calculations for the emissions of PM_{10} due to the drift from the unit.

4.4.3 Applicable State Emission Standards

a. The emission of smoke or other PM from the affected unit shall not have an opacity greater than 30 percent, except as allowed by 35 IAC 212.124. Compliance with this limit shall be determined by 6-minute averages of opacity measurements in accordance with USEPA Reference Method 9. [35 IAC 212.109 and 212.123(a)]

b. With respect to emissions of fugitive PM, the affected unit shall comply with 35 IAC 212.301, which provides that emissions of fugitive PM shall not be visible from any process, including any material handling or storage activity, when looking generally toward the zenith at a point beyond the property line of the source, except when the wind speed exceeds 25 miles per hour, as provided by 35 IAC 212.314.

c. The emissions of PM from the affected unit shall comply with the applicable limit pursuant to 35 IAC 212.321.

4.4.4 Applicability of Other Regulations

None

4.4.5 Operating Requirements

a. Chromium-based water treatment chemicals, as defined in 40 CFR 63.401, shall not be used in the affected unit.

b. i. Only non-VOM additives shall be used in the cooling tower.

ii. Plant process wastewater shall not be introduced into cooling water, other than through unintentional leaks, which shall promptly be repaired.

c. i. The affected unit shall be equipped with appropriate features, such as louvered heating coils designed to heat tower plenum air as required, to enable it to be operated without a significant contribution to fogging and icing on offsite roadways during periods when fogging or icing are present in the area or weather conditions are conducive to fogging or icing.

ii. Notwithstanding the above, such features need not be in the affected unit if the Permittee demonstrates by appropriate analysis, as approved in writing by the Illinois EPA, that the cooling tower will be sited and designed and can be operated such that additional features are not needed to prevent a significant contribution to fogging and icing on offsite roadways.

d. Any water supplied to the affected unit that is effluent from a wastewater treatment plant shall be tertiary wastewater, which is effluent treated by micro-filtration and disinfection to comply with the standards in the California Code of Regulations, 22 CCR 60301.230(a)(1) or (2), or other comparable standards approved by the Illinois EPA.

e. The Permittee shall operate and maintain the affected unit, including the drift eliminators, in a manner consistent with good air pollution control practices for minimizing emissions.

f. The Permittee shall operate and maintain the affected unit in accordance with written operating procedures, which procedures shall be kept current. These procedures shall address the practices that will be followed as good air pollution control practices and the actions that will be followed to prevent a significant contribution to icing and fogging on offsite roadways.

4.4.6 Emission Limitations

The emissions of particulate matter, as PM_{10}, from the affected unit shall not exceed 1.44 pounds per hour and 6.3 tons per year, as determined from relevant operating data for cooling tower and the efficiency of the drift eliminators, using engineering calculations for the emissions of PM_{10} due to the drift from the unit.

4.4.7 Emission Testing

None

4.4.8 Sampling and Analysis Requirement

a. The Permittee shall sample and analyze the water being circulated in the affected unit on at least a monthly basis for the total dissolved solids content. Measurements of the total dissolved solids content in the wastewater discharge associated with the affected unit, as required by a National Pollution Discharge Elimination System permit, may be used to satisfy this requirement if the effluent has not been diluted or otherwise treated in a manner that would significantly reduce its total dissolved solids content.

b. Upon written request by the Illinois EPA, the Permittee shall promptly have the water circulating in the affected unit sampled and analyzed for the presence of hexavalent chromium in accordance with the procedures of 40 CFR 63.404(a) and (b).

c. The Permittee shall keep records for this sampling and analysis activity, including documentation for sampling and analysis as well the resulting data that is collected.

4.4.9 Operational Measurements

Within 90 days after initial operation of the combustion turbines, the Permittee shall test the percent drift achieved by the drift eliminator pursuant to Cooling Technology Institute's Acceptance Test Code No. 140. This test shall be performed by a licensed performance testing service.

4.4.10 Records

a. The Permittee shall keep a file that contains:

i. The design loss specification for the drift eliminators installed in the affected unit.

ii. The suppliers' recommended procedures for inspection and maintenance of the drift eliminators.

iii. The operating factors, if any, used to determine the amount of water circulated in the affected unit or the PM emissions from the affected unit, with supporting documentation.

iv. Calculations for the maximum PM_{10} emissions from the cooling tower (pounds/hour, 24-hour average), based on maximum operating rate of the cooling tower and other factors that result in greatest emissions.

v. Copies of the Material Safety Data Sheets or other comparable information from the suppliers for the various water treatment chemicals that are added to the water circulated in the affected unit.

b. Records for the actions used to routinely verify the solids contents of the water circulating in the cooling tower, such as sampling and analysis in accordance with the NPDES permit, periodic grab sampling and analysis, conductivity measurements, etc., including:

   i. If routine verification will not be conducted pursuant to the NPDES permit, a written description of the procedures, with explanation of how they act to address compliance.

   ii. Records for implementation of the procedure, including measured value(s) of relevant parameter(s).

c. The Permittee shall keep the following operating records for the affected unit:

   i. The amount of water circulated in the affected unit, gallons/month. As an alternative to direct data for water flow, these records may contain other relevant operating data for the unit (e.g., water flow to the unit) from which the amount of water circulated in the unit may be reasonably determined.

   ii. Each occasion when the Permittee took action to prevent a significant contribution to fogging or icing from the affected unit, including the date and duration, the action or actions that were taken, the weather conditions that triggered such actions, and the weather conditions when such actions were terminated.

d. The Permittee shall keep inspection and maintenance logs for the drift eliminators installed in the affected unit.

e. The Permittee shall maintain records for the particulate matter emissions of the affected unit based on the above records, the measurements required by Condition 4.4.9(a), and appropriate emission estimation methodology and emission factors, with supporting calculation.

4.4.11 Notifications

The Permittee shall notify the Illinois EPA within 30 days of deviations from applicable requirements that are not addressed by the regular reporting required by Condition 4.4.12. These notifications shall include the information specified by Condition 6.5.

4.4.12 Reporting

The Permittee shall promptly notify the Illinois EPA of any deviations from the requirements of this permit for the cooling tower as follows. These notifications shall include the information specified by Conditions 6.3 - 6.5.

a. If the cooling tower is equipped with features to address fogging and icing, as addressed by Condition 4.4.5(b), the Permittee shall submit quarterly reports to the Illinois EPA summarizing the records required by Condition 4.4.10(b)(ii) and identifying any deviation from established practices for the use of such features.

b. If the cooling tower is damaged so there is a deviation from an applicable requirements that is not repaired or otherwise corrected within 24 hours, the Permittee shall then immediately notify the Illinois EPA.

c. The deviations addressed above and all other deviations shall be reported with the quarterly compliance report.

CONDITION 4.5: UNIT-SPECIFIC CONDITIONS FOR THE AUXILIARY BOILER

4.5.1 Description of Emission Unit

The affected unit for the purpose of these unit-specific permit conditions is a natural gas-fired "auxiliary" boiler that will be used to supply steam for startup of the gasifiers and the air separation unit. Given its function, the auxiliary boiler will only be operated on an intermittent basis and will be idle most of the time. The nominal rated capacity of the auxiliary boiler is 279 million Btu/hour. Emissions from the boiler are controlled by good combustion practices and low-NO_x burners.

4.5.2 Control Technology Determination

a. The affected boiler shall be operated and maintained with the following features to control emissions:

i. Low-NO_x burner

ii. Good Combustion Practices

b. i. The NO_x emissions of the affected boiler shall not exceed 0.036 lb/mmBtu based on a 24-hour block average.

ii. The CO emissions of the affected boiler shall not exceed 0.037 lb/mmBtu based on a 24-hour block average.

4.5.3-1 Applicable Federal Emission Standards

a. The affected boiler is subject to the New Source Performance Standards (NSPS) for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Db and related provisions of 40 CFR 60 Subpart A.

b. Sulfur dioxide (SO_2) emissions from the affected boiler shall not exceed 87 ng/J (0.20 lb/million Btu), based on a 30-day rolling average pursuant to 40 CFR 60.42b(k). This standard shall apply at all times, pursuant to 40 CFR 60.45b(a).

c. At all times, the Permittee shall maintain and operate the affected boiler, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions, pursuant to 40 CFR 60.11(d).

4.5.3-2 Applicable State Emission Standards:

a. The affected boiler is subject to 35 IAC 212.122(b), which provides that emissions of smoke or other particulate matter shall not have an opacity greater than 20 percent, except as allowed by 35 IAC 212.122(b) and 212.124. Compliance with this limit shall be determined by 6-minute averages of opacity measurements in accordance with USEPA Reference Method 9. [35 IAC 212.109 and 212.122(a)]

b. The affected boiler is subject to 35 IAC 216.121, which provides that emissions of carbon monoxide (CO) into the atmosphere shall not exceed 200 ppm, corrected to 50 percent excess air. [35 IAC 216.121]

c. The affected boiler is subject to 35 IAC 217.121, which provides that emissions of nitrogen oxide (NO_x) shall not exceed 0.2 lb/mmBtu of actual heat input in any one-hour period (35 IAC 217.121(a)).

4.5.3-3 Applicability of Other Regulations of Concern

None

4.5.4 Non-Applicability of Regulations of Concern

a. i. The affected boiler is not subject to the NSPS standards for PM and opacity, 40 CFR 60.43b because the SO_2 emissions will not exceed 0.32 lb/mmBtu heat input, as provided by 40 CFR 60.43b(h)(5).

ii. The affected boiler is not subject to the NSPS standards for NO_x, 40 CFR 60.44b, because the capacity factor of the boiler is limited to no more than 10 percent, as provided by 40 CFR 60.44b(1)(2).

iii. Continuous monitoring systems for NO_x emissions and opacity are not required for the affected boiler pursuant to the NSPS because the boiler is only fired on natural gas and has an annual capacity factor that is no more than 10 percent (see Condition 4.6.5(c)), so that these monitoring requirements of the NSPS do not apply, as provided by 40 CFR 60.48b(i) and 60.44b(j).

Note: If these criteria were not met, the affected boiler would be subject to requirements of the NSPS, as appropriate.

b. This permit is issued based on the affected boiler not being subject to the National Emission Standard for Hazardous Air Pollutants (NESHAP), 40 CFR 63, Subpart DDDDD, for Industrial, Commercial, and Institutional Boilers and Process Heaters because the source is not major for HAP.

Note: If the source were major for HAP, the affected boiler would be subject to this NESHAP.

c. The affected boiler is not subject to the Title IV (i.e., Acid Rain) provisions of the federal Clean Air Act since it is an industrial boiler.

4.5.5 Operational Limits and Work Practices

a. Natural gas shall be the only fuel fired in the affected boiler.

b. The usage of natural gas in the affected boiler shall not exceed 138 mmscf/year.

c. The annual capacity factor of the affected boiler shall not exceed 10 percent.

4.5.6 Emission Limitations

The emissions of the affected boiler shall not exceed the following limitations. Compliance with short-term limits in lbs/million Btu and lbs/hour shall be determined on a 24-hour average for NO_x and CO and a 3-hour average for other pollutants.

Pollutant	Lbs/mmBtu	Lbs/Hour	Tons/Year
CO	0.037[a]	10.3	2.6
PM	0.007	2.0	0.5
VOM	0.004	1.1	0.3
NO_x	0.036[a]	10.0	2.5
SO_2	0.006	1.7	0.4

Notes: [a] BACT Limit

4.5.7 Testing Requirements

a. i. Within 60 days after achieving the maximum production rate at which the affected boiler will be operated, but not later than 180 days after initial startup, the Permittee shall have emission tests conducted for emissions of NO_x, PM, CO and VOM, and opacity as specified below at its expense, by an approved testing service while the affected boiler is operating at maximum load and other representative operating conditions.

ii. In addition to the emission testing required above, the Permittee shall perform emission tests as requested by the Illinois EPA for the affected boiler within 45 days of a written request by the Illinois EPA or such later date agreed to by the Illinois EPA. The operating conditions during such testing shall be consistent with those specified by the Illinois EPA.

b. The following methods and procedures shall be used for testing of emissions of the affected boiler, unless another method is approved by the Illinois EPA.

Location of Sample Points	Method 1
Gas Flow and Velocity	Method 2
Flue Gas Weight	Method 3 or 3A
Moisture Content	Method 4

Nitrogen Oxides[1]	Method 7, 7E or 19
Opacity	Method 9
Carbon Monoxide	Method 10
Volatile Organic Material[2]	Method 18 and Method 25 or 25A
Particulate Matter[3]	Methods 5 and 202

[1] Test in accordance with 40 CFR 60, Subparts A and Db as specified in 40 CFR 60.48b(d).

[2] Permittee may exclude methane, ethane and other exempt compounds from the results of any VOM test provided that the test protocol to quantify and correct for such compounds is included in the test plan approved by the Illinois EPA.

[3] Testing for particulate matter (filterable and condensable) is required.

c. The Permittee shall submit a plan for emission testing to the Illinois EPA at least 60 days prior to the initial startup of the boiler.

d. The Illinois EPA shall be notified prior to these tests to enable the Illinois EPA to observe these tests. Notification and test protocol for the expected date of testing shall be submitted a minimum of thirty days prior to the expected date. Notification of the actual date and expected time of testing shall be submitted a minimum of 5 working days prior to the actual date of the test. Notwithstanding 40 CFR 60.8(d), the Illinois EPA may at its discretion accept notifications with shorter advance notice provided that the Illinois EPA will not accept such notifications if it interferes with the Illinois EPA's ability to observe testing.

e. Three copies of the Final Report for these tests shall be promptly submitted to the Illinois EPA and in no case later than 60 days after the completion of the testing, and shall include as a minimum:

i. A summary of results that includes:

- Boiler load (e.g., firing rate)
- Boiler operating parameters (i.e., steam produced and oxygen content in the flue gas leaving the boiler)
- Measured emission rates of all pollutants measured
- Emission factor, calculated using the average test results in the terms of the applicable limits, for example, in units of lbs pollutant emitted per mmBtu
- A statement whether compliance was demonstrated

ii. Description of test methods and procedures used, including description of sampling train, analysis equipment, and test schedule.

iii. Detailed description of test conditions, including:

- Pertinent process information (e.g. fuel type , quantity)

- Control equipment information, i.e., equipment condition and pressure drop, flow rates, and other operating parameters during testing

iv. Data and calculations, including copies of all raw data sheets and records of laboratory analyses, sample calculations, and data on equipment calibration.

f. Copies of emission test reports shall be retained for at least five years after the date that an emission test is superseded by a more recent test.

4.5.8 Monitoring Requirements

None

4.5.9 Recordkeeping Requirements

a. The Permittee shall maintain a file or other records for the affected boiler that contains the following information:

i. The maximum rated heat input of the affected boiler with supporting documentation.

ii. Records of the Permittee's established operating and maintenance procedures for the affected boiler.

b. The Permittee shall maintain records of information for NO_x for the affected boiler, for each boiler operating day, pursuant to the NSPS, 40 CFR 60.49b(p), which includes, but is not limited to:

i. Calendar date;

ii. The number of hours of operation; and

iii. A record of the hourly steam load.

c. Records for sulfur content (wt. percent) of the fuel supply to the affected boiler, including copies of the supplier certification of the fuel supplied to the affected boiler, as required by 40 CFR 60.45b(k), used to satisfy these requirements.

d. The Permittee shall maintain the following operating records for the affected boiler:

   i. Daily records of fuel use, in accordance with 40 CFR 60.49b(d); and

   ii. Amount of fuel consumed and the annual capacity factor, determined on a 12-month rolling basis with a new annual capacity factor calculated for each month pursuant to 40 CFR 60.49b(d). The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

e. The Permittee shall maintain the following logs or other records for the affected boiler:

   i. Each startup of the affected boiler, including the date and duration of each startup, and note any deviations from normal startup procedures, as set forth in the Permittee's written operating procedure.

   ii. An operating log that, at a minimum, includes:

      A. The information required by 40 CFR 60.7(b)

      B. Information on any malfunction or breakdown, including cause, duration and whether the affected boiler continued to operate during that time.

   iii. A maintenance and repair log for the affected boiler listing each activity performed with date.

f. The Permittee shall keep the following records related to emissions:

   i. Any period of time, including startup, shutdown, or malfunction, when emissions exceed an applicable limit.

   ii. The annual NO_x, CO, VOM, PM, SO_2 and HAP emissions from the affected boiler, based on continuous emissions monitoring data, fuel consumption or applicable emission factors with supporting calculations.

4.5.10 Reporting and Notification Requirements

a. The Permittee shall fulfill applicable reporting requirements of the NSPS, 40 CFR 60.7 and 60.49b, for the affected boiler by sending the following notifications and reports to the Illinois EPA:

   i. Notification of the date of initial startup of the affected boiler, as provided by 40 CFR 60.7. This notification shall include: (1) the design heat input capacity of the affected boiler, (2) identification of the fuels to be combusted in the boiler, and (3) the annual capacity factor at which the Permittee anticipates operating the affected boiler.

ii. Reports containing the information recorded under 40 CFR 60.49b(b).

iii. Reports for excess emissions (see Condition 4.5.10(c)). These reports shall be prepared and submitted in conformance with the requirements, content and schedule contained in 40 CFR 60.7 and 60.49b(v).

iv. A report for the maximum rated heat input capacity data of the affected boiler.

b. The Permittee shall immediately notify the Illinois EPA of any occurrence when the NO_x emissions from the affected boiler exceed the applicable emission standard or limitation or emissions of other pollutants exceed the applicable standard or limitation.

c. i. The Permittee shall submit excess emission reports for any calendar quarter during which there are excess NO_x emissions from the affected boiler pursuant to the NSPS. If there are no excess NO_x emissions during the calendar quarter, the Permittee shall submit a report stating that no excess emissions occurred during the reporting period. Excess emissions are defined as any calculated emission rate that exceeds the applicable limit in Condition 4.5.6.

ii. Except for deviations by the affected boiler addressed by the above quarterly reports, the Permittee shall notify the Illinois EPA of any deviations of the affected boiler from any applicable requirement of this permit as outlined in Conditions 4.5.10(a)(iii) and (c).

iii. The reporting period for the reports is quarterly. All reports shall be submitted and be postmarked by the 30th day following the end of the reporting period.

CONDITION 4.6: UNIT-SPECIFIC CONDITIONS FOR ROADWAYS AND OTHER OPEN AREAS

4.6.1 Description of Emission Units

The affected units for the purpose of these unit-specific conditions are roadways, parking areas, the slag disposal landfill and other open areas associated with the operation of the plant, which may be sources of fugitive particulate matter due to vehicle traffic or wind blown dust. These emissions are controlled by paving and implementation of work practices to prevent the generation and emissions of particulate matter.

4.6.2 Control Technology Determination

a. The opacity of fugitive particulate matter emissions from affected units, except during periods of high wind speeds, shall not exceed 15 percent opacity. For this purpose, opacity and the presence of high wind speeds shall be determined in accordance with 35 IAC 212.109 and 35 IAC 212.314, respectively.

b. i. Good air pollution control practices shall be implemented to minimize dust emissions from affected units. After construction of the plant is complete, these practices shall provide for pavement on all regularly traveled roads and treatment (flushing, vacuuming, dust suppressant application, etc.) of roadways and areas that are routinely subject to vehicle traffic for very effective and effective control of dust, respectively (nominal 90 percent control for paved roads and areas and 85 percent control for unpaved roads and areas).

ii. For this purpose, roads that serve any office building, employee parking areas or are used on a daily basis by operating and maintenance personnel for the plant in the course of their typical duties, roads that experience heavy use during regularly occurring maintenance of the plant during the course of a year, shall all be considered to be subject to regular travel and are required to be paved. Regularly traveled roads shall be considered to be subject to routine vehicle traffic except as they are used primarily for periodic maintenance and are currently inactive or as traffic has been temporarily blocked off. Other roads shall be considered to be routinely traveled if activities are occurring such that they are experiencing significant vehicle traffic.

c. The handling of material collected from any affected unit associated with the plant by sweeping or vacuuming trucks shall be enclosed or shall utilize spraying, pelletizing, screw conveying or other equivalent methods to control PM emissions.

4.6.3-1 Applicable Federal Emission Standards

None

4.6.3-2 Applicable State Emission Standards

All affected units shall comply with 35 IAC 212.301, which provides that emissions of fugitive particulate matter shall not be visible from any process, including material handling, storage activity, or any landfilling operation when looking generally toward the zenith at a point beyond the property line of the source, except when the wind speed is greater than 25 miles per hour, as provided by 35 IAC 212.314.

4.6.3-3 Applicability of Other Regulations

None

4.6.4 Non-Applicability of Regulations of Concern

None

4.6.5 Operational and Production Limits and Work Practices

a. The Permittee shall carry out control of fugitive particulate matter emissions from affected units in accordance with a written operating program describing the measures being implemented in accordance with Conditions 4.6.2 and 4.6.3 to control emissions at each unit with the potential to generate significant quantities of such emissions, which program shall be kept current.

i. The written operating program shall include:

A. Maps or diagrams indicating the location of affected units with the potential to generate significant quantities of fugitive particulate matter, with description of the unit (length, width, surface material, etc.) and volume and nature of expected vehicle traffic, or other activity on such unit, and an identification of any roadways that are not considered routinely traveled, with justification.

B. A detailed description of the emissions control technique(s) (e.g., vacuum truck, water spray, surfactant spray, water flushing, dust suppressant application, or sweeping) for the affected unit, including: typical application rate; type and concentration of additives; normal frequency with which measures would be implemented; circumstances, in which the measure would not be implemented, e.g., recent precipitation; triggers for additional control, e.g., observation of 12 percent opacity; and calculated control efficiency for PM emissions.

ii. The Permittee shall submit copies of the written operating program to the Illinois EPA for review as follows:

A. A program addressing affected units during the construction of the plant shall be submitted within 30 days of beginning actual construction of the plant.

B. A program addressing affected units with the operation of the affected plant shall be submitted within 90 days of initial start up of the plant.

C. Significant amendments to the program by the Permittee shall be submitted within 30 days of the date that the amendment is made.

iii. A revised operating program shall be submitted to the Illinois EPA for review within 90 days of a request from the Illinois EPA for revision to address observed deficiencies in control of fugitive particulate matter emissions.

b. The Permittee shall conduct inspections of affected units on at least a weekly basis during construction of the plant and on a monthly basis thereafter with personnel not directly responsible for the day-to-day implementation of the fugitive dust control program, for the specific purpose of verifying that the measures identified in the operating program and other measures required to control emissions from affected units are being properly implemented.

4.6.6 Emission Limitations

The emissions of PM from affected units, as PM_{10}, shall not exceed the following limits. Compliance with these limits shall be determined by vehicle traffic and other operating data for the plant, information for the implementation of the operating program, appropriate emission factors, and engineering calculations:

Total emissions from the affected units shall not exceed 1.1 tons/year.

4.6.7-1 Emission Testing

None

4.6.7-2 Opacity Observations

a. The Permittee shall conduct performance observations, which include a series of observations of the opacity of fugitive emissions from the affected units as follows to determine the range of opacity from affected units and the change in opacity as related to the amount and nature of vehicle traffic and implementation of the operating program. For performance observations, the Permittee shall submit test plans, test notifications and test reports, as specified by General Condition 6.2.

i. Performance observations shall first be completed no later than 30 days after the date that initial emission testing of the affected combustion turbines are performed, as required by Condition 4.2.8, in conjunction with the measurements of silt loading on the affected units required by Condition 4.6.10.

ii. Performance observations shall be repeated within 30 days in the event of changes involving affected units that would act to increase opacity (so that observations that are representative of the current circumstances of the affected units have not been conducted), including changes in the amount or type of traffic on affected units, changes in the standard operating practices for affected units, such as application of salt or traction material during cold weather, and changes in the operating program for affected units.

b. Compliance observations shall be conducted for affected units on at least a quarterly basis to verify opacity levels and confirm the effectiveness of the operating program in controlling emissions.

c. Upon written request by the Illinois EPA, the Permittee shall conduct performance or compliance observations, as specified in the request. Unless another date is agreed to by the Illinois EPA, performance observations shall be completed within 30 days and compliance observations shall be completed within 5 days of the Illinois EPA's request.

4.6.8 Operational Measurements

The Permittee shall conduct measurements of the silt loading on various affected roadway segments and parking areas, as follows:

a. Sampling and analysis of the silt loading shall be conducted using the "Procedures for Sampling Surface/Bulk Dust Loading," Appendix C.1 in Compilation of Air Pollutant Emission Factors, USEPA, AP-42. A series of samples shall be taken to determine the average silt loading and address the change in silt loadings as related to the amount and nature of vehicle traffic and implementation of the operating program.

b. Measurements shall be performed by the following dates:

i. Measurements shall first be completed no later than 30 days after the date that initial emission testing of the affected CTs are performed, as required by Condition 4.2.7.

ii. Measurements shall be repeated within 30 days in the event of changes involving affected units that would act to increase silt loading (so that data that is representative of the current circumstances of the affected units has not been collected), including changes in the amount or type of traffic on affected units, changes in the standard operating practices for affected units, such as application of salt or traction material during cold weather, and changes in the operating program for affected units.

iii. Upon written request by the Illinois EPA, the Permittee shall conduct measurements, as specified in the request, which shall be completed within 75 days of the Illinois EPA's request.

c. The Permittee shall submit test plans, test notifications and test reports for these measurements as specified by General Condition 6.2, provided, however, that once a test plan has been accepted by the Illinois EPA, a new test plan need not be submitted if the accepted plan will be followed or a new test plan is requested by the Illinois EPA.

4.6.9 Records

a. The Permittee shall keep a file that contains:

i. The operating factors, if any, used to determine the amount of activity associated with the affected units or the PM emissions from the affected units, with supporting documentation.

ii. The designated PM emission rate, in tons/year, from each category of affected units (e.g., traffic associated with receiving of coal, with supporting calculations and documentation. The sum of these rates shall not exceed the annual limit on emissions in Condition 4.6.6.

b. The Permittee shall maintain records documenting implementation of the operating program required by Condition 4.6.5, including:

i. Records for each treatment of an affected unit or units:

A. The identity of the affected unit(s), the date and time, and the identification of the truck(s) or treatment equipment used;

B. For application of dust suppressant by truck: target application rate or truck speed during application, total quantity of water or chemical used and, for application of a chemical or chemical solution, the identity of the chemical and concentration, if applicable;

C. For sweeping or cleaning: Identity of equipment used and identification of any deficiencies in the condition of equipment; and

D. For other type of treatment: A description of the action that was taken.

ii. Records for each incident when control measures were not implemented and each incident when additional control measures were implemented due to particular activities, including description, date, a statement of explanation, and expected duration of such circumstances.

c. The Permittee shall record any period during which an affected unit was not properly controlled as required by this permit, which records shall include at least the information specified by General Condition 6.3 and an estimate of the additional PM emissions that resulted, if any, with supporting calculations.

d. The Permittee shall keep records for the measurements conducted for affected units pursuant to Condition 4.6.8, including records for the sampling and analysis activities and results.

e. The Permittee shall maintain records for the PM emissions of the affected units to verify compliance with the limits in Condition 4.6.6, based on operating data for the affected gasification trains and other activities at the plant, the above records for the affected units including data for implementation of the operating program, and appropriate USEPA emission estimation methodology and emission factors, with supporting calculations.

4.6.10 Notifications

The Permittee shall notify the Illinois EPA within 30 days of deviations from applicable requirements for affected units that are not addressed by the regular reporting required below. These notifications shall include the information specified by General Condition 6.5.

4.6.11 Reporting

The Permittee shall submit quarterly reports to the Illinois EPA for affected units stating the following: the dates any necessary control measures were not implemented; a listing of those control measures; the reasons that the control measures were not implemented; and any corrective actions taken. This information includes, but is not limited to, those dates when controls were not implemented based on a belief that implementation of such control measures would have been unreasonable given prevailing weather conditions. This report shall be submitted to the Illinois EPA no later than 45 calendar days from the end of each calendar quarter.

SECTION 5: EMISSION CONTROL PROGRAM CONDITIONS

CONDITION 5.1: ACID RAIN PROGRAM

a. Applicability

Under Title IV of the federal Clean Air Act, Acid Deposition Control, this plant or source is an affected source and the following emission units at the source are affected units for acid deposition (see Condition 4.2 for more information):

Combustion Turbines 1 and 2

Note: Title IV of the Clean Air Act, and other laws and regulations promulgated thereunder, establish requirements for affected sources related to control of emissions of pollutants that contribute to acid rain, i.e., SO_2 and NO_x. For purposes of this permit, these requirements are referred to as Title IV provisions.

b. Applicable Emission Requirements

The owners and operators of the source shall not violate applicable Title IV provisions. In particular, SO_2 emissions of the affected units shall not exceed any allowances that the source lawfully holds under Title IV provisions. [Environmental Protection Act, Sections 39.5(7)(g) and (17)(1)]

Note: Affected sources must hold SO_2 allowances to account for the SO_2 emissions from affected units at the source that are subject to Title IV provisions. Each allowance is a limited authorization to emit up to one ton of SO_2 emissions during or after a specified calendar year. The possession of allowances does not authorize exceedances of applicable emission standards or violations of ambient air quality standards.

c. Monitoring, Recordkeeping and Reporting

The owners and operators of the source and, to the extent applicable, their designated representative, shall comply with applicable requirements for monitoring, recordkeeping and reporting specified by Title IV provisions, including 40 CFR Part 75. [Environmental Protection Act, Sections 39.5(7)(b) and 17(m)]

d. Acid Rain Permit

The owners and operators of the source shall comply with the terms and conditions of the source's Acid Rain permit. [Environmental Protection Act, Section 39.5(17)(1)]

Note: The source is subject to an Acid Rain permit, which was issued pursuant to Title IV provisions, including Section 39.5(17) of the Environmental Protection Act. Affected sources must be operated in compliance with their Acid Rain permits. A copy of the initial Acid Rain permit is included as an attachment to this permit. Revisions and modifications of this Acid Rain permit, including administrative amendments and automatic amendments (pursuant to Sections 408(b) and 403(d) of the CAA or regulations thereunder) are governed by Title IV provisions, as provided by Section 39.5(13)(e) of, the Environmental Protection Act, and revision or renewal of the Acid Rain permit may be handled separately from this permit.

e. Coordination with Other Requirements

i. This permit does not contain any conditions that are intended to interfere with or modify the requirements of Title IV provisions. In particular, this permit does not restrict the flexibility under Title IV provisions of the owners and operators of this source to amend their Acid Rain compliance plan. [Environmental Protection Act, Section 39.5(17)(h)]

ii. Where another applicable requirement of this permit is more stringent than an applicable requirement of Title IV provisions, both requirements are enforceable and the owners and operators of the source shall comply with both requirements. [Environmental Protection Act, Section 39.5(7)(h)]

SECTION 6: GENERAL PERMIT CONDITIONS

CONDITION 6.1: STANDARD CONDITIONS

Standard conditions for issuance of construction permits, attached hereto and incorporated herein by reference, shall apply to this project, unless superseded by other conditions in the permit.

CONDITION 6.2: GENERAL REQUIREMENTS FOR EMISSION TESTING

a. i. At least 60 days prior to the actual date of initial emission testing required by this permit, a written test plan shall be submitted to the Illinois EPA for review. This plan shall describe the specific procedures for testing and shall include at a minimum:

A. The person(s) who will be performing sampling and analysis and their experience with similar tests.

B. The specific conditions, e.g., operating rate and control device operating conditions, under which testing shall be performed including a discussion of why these conditions will be representative and the means by which the operating parameters will be determined.

C. The specific determinations of emissions that are intended to be made, including sampling and monitoring locations.

D. The test method(s) that will be used, with the specific analysis method if the method can be used with different analysis methods.

ii. As provided by 35 IAC 283.220(d), the Permittee need not submit a test plan for subsequent emissions testing that will be conducted in accordance with the procedures used for previous tests accepted by the Illinois EPA or the previous test plan submitted to and approved by the Illinois EPA, provided that the Permittee's notification for testing, as required below, contains the information specified by 35 IAC 283.220(d)(1)(A), (B) and (C).

b. i. The Permittee shall notify the Illinois EPA prior to performing emissions testing required by this permit to enable the Illinois EPA to observe the tests. Notification for the expected date of testing shall be submitted a minimum of 30 days* prior to the expected date, and identify the testing that will be performed. Notification of the actual date and expected time of testing shall be submitted a minimum of 5 working days* prior to the actual date of testing.

* For a particular test, the Illinois EPA may at its discretion accept shorter advance notification provided that it does not interfere with the Illinois EPA'S ability to observe testing.

ii. This notification shall also identify the parties that will be performing testing and the set or sets of operating conditions under which testing will be performed.

c. Three copies of the Final Reports for emission tests shall be forwarded to the Illinois EPA within 30 days after the test results are compiled and finalized but not later than 90 days after the date of testing. At a minimum, the Final Report for testing shall contain:

i. General information, i.e., testing personnel and test dates;

ii. A summary of results;

iii. Description of test method(s), including a description of sampling points, sampling train, analysis equipment, and test schedule;

iv. The operating conditions of the emission unit and associated control devices during testing; and

v. Data and calculations, including copies of all raw data sheets and records of laboratory analysis, sample calculations, and data on equipment calibration.

CONDITION 6.3: GENERAL REQUIREMENTS FOR RECORDS FOR DEVIATIONS

Except as specified in a particular provision of this permit or in a subsequent CAAPP Permit for the plant, records for deviations from applicable emission standards and control requirements shall include at least the following information: the date, time and estimated duration of the event; a description of the event; the manner in which the event was identified, if not readily apparent; the probable cause for deviation, if known, including a description of any equipment malfunction/breakdown associated with the event; information on the magnitude of the deviation, including actual emissions or performance in terms of the applicable standard if measured or readily estimated; confirmation that standard procedures were followed or a description of any event-specific corrective actions taken; and a description of any preventative measures taken to prevent future occurrences, if appropriate.

CONDITION 6.4: RETENTION AND AVAILABILITY OF RECORDS

Except as specified in a particular provision of this permit or in a subsequent CAAPP Permit for the plant, all records and logs required by this permit shall be retained at a readily accessible location at the source for at least five years from the date of entry and shall be available for inspection and copying by the Illinois EPA upon request. Any record retained in an electronic format (e.g., computer) shall be capable of being retrieved and printed on paper during normal source office hours so as to be able to respond to an Illinois EPA request for records during the course of an on-site inspection.

CONDITION 6.5: NOTIFICATION AND REPORTING OF DEVIATIONS

Except as specified in a particular provision of this permit or in a subsequent CAAPP Permit for the plant, notifications and reports for deviation from applicable emission standards and control requirements shall include at least the following information: the date and time of the event, a description of the event, information on the magnitude of the deviation, a description of the corrective measures taken, and a description of any preventative measures taken to prevent future occurrences.

CONDITION 6.6: GENERAL REQUIREMENTS FOR NOTIFICATION AND REPORTS

a. i. Unless otherwise specified in the particular provision of this permit or in the written instructions distributed by the Illinois EPA for particular reports, reports and notifications shall be sent to the Illinois EPA - Air Compliance Section with a copy sent to the Illinois EPA - Air Regional Field Office.

ii. As of the date of issuance of this permit, the addresses of the office that should generally be utilized for the submittal of reports and notifications are as follows:

A. Illinois EPA - Air Compliance Section

Illinois Environmental Protection Agency
Bureau of Air
Compliance and Enforcement Section (#40)
P.O. Box 19276
Springfield, Illinois 62794-9276

B. Illinois EPA - Air Regional Field Office

Illinois Environmental Protection Agency
Division of Air Pollution Control
2009 Mall Street
Collinsville, Illinois 62234

C. USEPA Region 5 - Air Branch

USEPA (AE-17J)
Air and Radiation Division
77 West Jackson Boulevard
Chicago, Illinois 60604

b. The Permittee shall submit Annual Emission Reports to the Illinois EPA in accordance with 35 IAC Part 254. For hazardous air pollutants, these reports shall include emissions information for at least the following pollutants: hydrogen chloride, hydrogen fluoride, and mercury.

ATTACHMENTS

ATTACHMENT 1: SUMMARY OF PERMITTED EMISSIONS AND EMISSION LIMITATIONS

Table I

Emission Limitations for Combustion Turbines (CTs)

Pollutant	Individual Combustion Turbines				Combined Tons/Year[b]
	Syngas Lbs/Million Btu[a]	Natural Gas Lbs/Million Btu[a]	Rate Lbs/Hour	Averaging Time	
NO_x	0.034[c]	0.025[c]	71.8	24-Hour Average[c]	628.6
CO	0.049[d]	0.045[d]	105.0	24-Hour Average	919.9
VOM	0.0015	0.0017	3.2	3-Hour Average	28.1
SO_2	0.016	0.001	34.2	3-Hour Average	299.2
PM/PM_{10} Filterable[e]	0.009[f]	0.007[f]	18.4	3-Hour Average	161.2
PM_{10} Total	0.022[f]	0.011[f]	47.0	3-Hour Average	405.5
Sulfuric Acid Mist	0.0035[g]	0.0001	7.6	3-Hour Average	66.6
Fluorides[h]	-----	-----	0.07	3-Hour Average	0.6132
Lead[i]	-----	-----	0.0023	3-Hour Average	0.0196
Hydrogen Chloride	-----	-----	0.85	3-Hour Average	7.45
Mercury	0.00002[j]	-----	-----	-----	0.067

Notes:

[a] Compliance with the emission limitation expressed in pound/million Btu heat input shall be determined in accordance with the provisions in Condition 4.2.2(b) based on the higher heating value of the fuel. These emissions limitations are based on the hourly emission rate provided in the application using combustion turbine fuel input, not gasifier heat input. Only the SO_2 limit applies during startup and shutdown.

[b] These limitations address all emissions from the CTs, including emissions that occur during periods of startup, shutdown and malfunction addressed by Condition 4.2.6.

[c] This limitation does not apply during startup and shutdown. The emissions of NO_x from the CTs during such periods are addressed by the lbs/hour BACT limit for NO_x, which applies as a 24-hour block average.

[d] This emission limit does not apply for startup or shutdown of a CT. The emissions of CO from a CT during such periods are addressed by a limitation expressed as 105.0 pounds/hour, 24-hour average basis, which is the product of the design capacity of the CT, in million Btu/hour, and the otherwise applicable BACT limit in lbs/million Btu.

[e] All particulate matter (PM) measured by USEPA Method 5 shall be considered as PM_{10}, unless PM emissions are tested by USEPA Method 201 or 201A as specified in 35 IAC 214.108(a).

[f] This emission limit does not apply for startup or shutdown of a CT. The emissions of PM/PM_{10} filterable and PM Total from a CT during such periods are addressed by a 22.62 pounds/hour limitation, 3-hour average basis.

[g] This emission limit does not apply for startup or shutdown of a CT. The emissions of H_2SO_4 from a CT during such periods are addressed by a limitation expressed as 7.6 pounds/hour, 3-hour average basis, which is the product of the design capacity of the CT, in million Btu/hour, and the otherwise applicable BACT limit in lbs/million Btu.

[h] The limit for fluorides is expressed as hydrogen fluorides.

[i] The limit for lead is expressed in terms of elemental lead.

[j] Expressed in lbs/MWh, 12-month rolling average (for syngas and natural gas).

TABLE II

Particulate Matter (PM) Emission Limitations for Bulk Material Operations
(Tons per Year)

Emission Units	Application Designation	Tons/Year
Coal Handling and Storage	Railroad Unloading Operations	0.84
Slag Handling and Disposal	Slag Maintenance and Wind Erosion	1.10
Total		1.94

Table III
Permitted Annual Emissions
Plantwide
(Tons Per Year)

Pollutant	Power Block	Gasification Block			Auxiliary Boiler	Cooling Tower	Material Handling and Storage	Engine	Total
		Normal		Startup					
		Sulfur Unit	Flare						
NO_x	628.6	71.9	0.21	48.8	2.5	---	---	0.06	752.0
CO	919.9	41.5	0.20	79.7	2.6	---	---	0.05	1043.9
VOM	28.1	2.8	0.02	2.2	0.3	---	---	0.01	33.4
SO_2	299.2	91.2	0.01	44.9	0.4	---	---	0.01	435.7
PM_{10} (Filterable)	161.2	2.8	0.01	7.1	0.5	6.31	1.94	0.01	179.9
Total PM_{10}	405.5	2.8	0.01	7.1	0.5	6.31	1.94	0.01	424.2
Sulfuric Acid Mist	66.6	---	---	10.0	0.1	---	---	---	76.7

ATTACHMENT 2: STANDARD PERMIT CONDITIONS

STANDARD CONDITIONS FOR CONSTRUCTION/DEVELOPMENT PERMITS
ISSUED BY THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

The Illinois Environmental Protection Act (Illinois Revised Statutes, Chapter 111-1/2, Section 1039) authorizes the Illinois Environmental Protection Agency to impose conditions on permits which it issues.

The following conditions are applicable unless superseded by special condition(s).

1. Unless this permit has been extended or it has been voided by a newly issued permit, this permit will expire one year from the date of issuance, unless a continuous program of construction or development on this project has started by such time.

2. The construction or development covered by this permit shall be done in compliance with applicable provisions of the Illinois Environmental Protection Act and Regulations adopted by the Illinois Pollution Control Board.

3. There shall be no deviations from the approved plans and specifications unless a written request for modification, along with plans and specifications as required, has been submitted to the Illinois EPA and a supplemental written permit issued.

4. The Permittee shall allow any duly authorized agent of the Illinois EPA, upon the presentation of credentials, at reasonable times:

   a. To enter the Permittee's property where actual or potential effluent, emission or noise sources are located or where any activity is to be conducted pursuant to this permit;

   b. To have access to and to copy any records required to be kept under the terms and conditions of this permit;

   c. To inspect, including during any hours of operation of equipment constructed or operated under this permit, such equipment and any equipment required to be kept, used, operated, calibrated and maintained under this permit;

   d. To obtain and remove samples of any discharge or emissions of pollutants; and

   e. To enter and utilize any photographic, recording, testing, monitoring or other equipment for the purpose of preserving, testing, monitoring, or recording any activity, discharge, or emission authorized by this permit.

5. The issuance of this permit:

a. Shall not be considered as in any manner affecting the title of the premises upon which the permitted facilities are to be located;

b. Does not release the Permittee from any liability for damage to person or property caused by or resulting from the construction, maintenance, or operation of the proposed facilities;

c. Does not release the Permittee from compliance with other applicable statutes and regulations of the United States, of the State of Illinois, or with applicable local laws, ordinances and regulations;

d. Does not take into consideration or attest to the structural stability of any units or parts of the project; and

e. In no manner implies or suggests that the Illinois EPA (or its officers, agents or employees) assumes any liability, directly or indirectly, for any loss due to damage, installation, maintenance, or operation of the proposed equipment or facility.

6a. Unless a joint construction/operation permit has been issued, a permit for operation shall be obtained from the Illinois EPA before the equipment covered by this permit is placed into operation.

b. For purposes of shakedown and testing, unless otherwise specified by a special permit condition, the equipment covered under this permit may be operated for a period not to exceed thirty (30) days.

7. The Illinois EPA may file a complaint with the Board for modification, suspension or revocation of a permit,

a. Upon discovery that the permit application contained misrepresentations, misinformation or false statement or that all relevant facts were not disclosed; or

b. Upon finding that any standard or special conditions have been violated; or

c. Upon any violations of the Environmental Protection Act or any regulation effective thereunder as a result of the construction or development authorized by this permit.

ATTACHMENT 3: ACID RAIN PERMIT

217-782-2113

ACID RAIN PROGRAM PERMIT

Christian County Generation, LLC
Attn: Michael McInnis, Designated Representative
4350 Brownsboro Road, Suite 110
Louisville, Kentucky 40207

Oris No.:	
Illinois EPA I.D. No.:	021060ACB
Source/Unit:	Christian County Generation, LLC, Units 01 and 02
Date Received:	April 14, 2005
Date Issued:	June 5, 2007
Effective Date:	January 1, 2008
Expiration Date:	December 31, 2012

STATEMENT OF BASIS:

In accordance with Section 39.5(17)(b) of the Illinois Environmental Protection Act and Titles IV and V of the Clean Air Act, the Illinois Environmental Protection Agency is issuing this Acid Rain Program permit for the Christian County Generation.

SULFUR DIOXIDE (SO_2) ALLOCATIONS AND NITROGEN OXIDE (NO_x) REQUIREMENTS FOR EACH AFFECTED UNIT:

Unit 01 and Unit 02	SO_2 Allowances	These units are not entitled to an allocation of SO_2 allowances pursuant to 40 CFR Part 73.
	NO_x Emission Limitation	None

This Acid Rain Program permit contains provisions related to sulfur dioxide (SO_2) emissions and requires the owners and operators to hold SO_2 allowances to account for SO_2 emissions beginning in the year 2000. An allowance is a limited authorization to emit up to one ton of SO_2 during or after a specified calendar year. Although this plant is not eligible for an allowance allocated by USEPA, the owners or operators may obtain SO_2 allowances to cover emissions from other sources under a marketable allowance program. The transfer of allowances to and from a unit account does not necessitate a revision to this permit (See 40 CFR 74.84).

This permit contains provisions related to nitrogen oxide (NO_x) emissions requiring the owners or operators to monitor NO_x emissions from affected units in accordance with the applicable provisions of 40 CFR Part 75.

This Acid Rain Program permit does not authorize the construction and operation of the affected units as such matters are addressed by Titles I and V of the Clean Air Act. If the construction and operation of one of the affected units is not undertaken, this permit shall not cover such unit.

In addition, notwithstanding the effective date of this permit as specified above, this permit shall not take effect for an individual affected unit until January 1 of the year in which the unit commences operation.

COMMENTS, NOTES AND JUSTIFICATIONS:

This permit does not affect the owner's and operator's responsibility to meet all other applicable local, state, and federal requirements, including requirements addressing SO_2 and NO_x emissions.

PERMIT APPLICATION:

The SO_2 allowance requirements and other standard requirements as set forth in the application are incorporated by reference into this permit. The owners and operators of this source must comply with the standard requirements and special provisions set forth in the application.

If you have any questions regarding this permit, please contact Bob Smet at 217/782-2113.

Edwin C. Bakowski, P.E.
Acting Manager, Permits Section
Division of Air Pollution Control

ECB:RPS:psj

cc: Cecilia Mijares, USEPA Region V
Illinois EPA Region 3

Illinois Environmental Protection Agency
Bureau of Air, Permit Section
1021 North Grand Avenue East
P.O. Box 19276
Springfield, Illinois 62794-9276
217/782-2113

Project Summary
for a Construction Permit Application
from Christian County Generation, LLC
for the
Taylorville Energy Center
Christian County, Illinois

Site Identification No.: 021060ACB
Application No.: 05040027
Date Received: April 14, 2005

Schedule:

Public Comment Period Begins:
Public Hearing:
Public Comment Period Closes:

Illinois EPA Contacts:

Permit Analyst: Robert Smet
Community Relations Coordinator: Brad Frost

I. INTRODUCTION

Christian County Generation, LLC, has submitted an application for a permit to construct a net nominal 630 megawatt (MW) electric power plant, the Taylorville Energy Center (TEC), approximately 1.5 miles northeast of Taylorville. The plant would use Integrated Gasification Combined Cycle (IGCC) technology with Illinois Basin coal as the design feedstock.

Christian County Generation must obtain an air pollution control construction permit from the Illinois EPA for the proposed plant because the plant would be a source of emissions. The Illinois EPA has reviewed Christian County Generation's application and made a preliminary determination that the application for the proposed project meets applicable requirements. Accordingly, the Illinois EPA has prepared a draft of the construction permit that it would propose to issue for the proposed plant. The Illinois EPA has also prepared a draft Acid Rain Permit for the plant, to address requirements under the federal Acid Rain program. However, before issuing these permits, the Illinois EPA is holding a public comment period with hearing to receive comments on the proposed issuance of permits and the terms and conditions of the draft permits.

II. PROJECT DESCRIPTION

The proposed power plant would use Integrated Gasification Combined Cycle technology to generate electric power. With IGCC technology, a feedstock is first processed by gasification to produce a synthetic fuel gas (syngas). The feedstock for the proposed plant would be Illinois Basin coal (Herrin No. 6). The syngas from the proposed plant would be a low Btu fuel gas with a heat content of approximately 250 Btu/cubic foot. The principal components of the syngas would be hydrogen and carbon monoxide. This syngas fuel is then burned in separate gas turbine combustion equipment to generate electric power. Electric power is also generated from heat energy recovered as steam from the gasification process.

The plant is being developed to operate as a base load power plant, with each combustion turbine running for months at a time, ideally at or near capacity. The plant would employ two identical "trains," each with half the capacity of the plant. The plant would also have a "spare" third gasifier so that the plant could continue to operate at full capacity during maintenance or outage of either of the gasifiers. This will increases the reliability of electric power generation and the availability of the plant.

After accounting for power consumed in operating the plant, the plant would have a nominal net output of about 630 MW to the grid. The plant would also generate about 140 MW of electricity that would be consumed in operating the plant itself. The nominal heat input of the plant would be 5,835 million Btu/hour.

Much of the power consumed at the plant would be used in the air separation unit. In this unit, ambient air is separated into oxygen and nitrogen using low temperature refrigeration and high pressure. The oxygen is used in the gasification process, where concentrated oxygen improves process efficiency, as compared to use of air, which is only about 21% oxygen. The pressurized nitrogen stream from the air separation unit is used in the combustion turbines to generate electric power. The introduction of nitrogen into the turbines also lowers the peak flame temperatures in the turbines, which acts to reduce NO_x emissions.

The gasification block would have three identical gasifiers (one spare) and two identical, parallel gas cleanup trains, as already explained. Raw syngas would be produced from coal slurry and oxygen in the gasifiers. The raw syngas would then undergo a series of processes in two gas cleanup trains to clean the gas and prepare the raw gas for use as fuel. These processes would include cooling, removal of entrained particulate matter, mercury removal, and removal of sulfur compounds and other acid gases from the raw syngas. A more detailed description of the gasification process is provided in Attachment 2.

The only direct emissions from the gasifier block would normally occur from the sulfur recovery unit. The sulfur recovery unit further processes the raw syngas to remove sulfur compounds, converting them into elemental sulfur, which is also a byproduct from the plant. This conversion process can still generate sulfur compounds such as SO_2 and H_2S, which are controlled with a tail-gas treatment unit and thermal oxidizer.

The gasifier block would also be a direct source of emissions during upsets, when processed syngas could not be sent on to the power block. These upset emissions would occur from a flare, which would be designed to safely combust and dispose of syngas under these circumstances.

After cleaning, the syngas would be supplied to the power block where it would be fired in two combined-cycle combustion turbines to produce electricity. As combined-cycle turbines, the turbines are followed by heat recovery steam generators, which produce steam from the hot exhaust from the turbines. At the proposed plant, this steam will be combined with steam from the various heat exchangers in the gasification block and used in a steam turbine to also produce electric power. The turbines will have natural gas firing capability for start-up and emergency operation. The exhaust from each turbine and heat recovery steam generator pair is vented to the atmosphere through 199 foot high stacks.

Emissions from the power block are controlled or minimized by using appropriately designed syngas cleanup technologies for PM, mercury and sulfur compounds, good combustion practices, introduction of nitrogen into the turbines with its diluent effect, and add-on selective catalytic reduction (SCR) systems.

Other emission units at the proposed plant would include: storage, processing and handling equipment for coal, slag, and other bulk materials; a cooling tower; an auxiliary boiler; various roads and parking areas; and engines for backup and emergency power for the plant.

III. PROJECT EMISSIONS

The principal emission units at the proposed plant are the two combustion turbines and associated heat recovery steam turbine generators. The potential emissions of the turbines are listed below. Potential emissions are calculated based on continuous operation at the maximum load. Actual emissions will be less to the extent that the turbines would not operate at its maximum capacity.

Pollutant	Potential Emissions (Tons Per Year)
Particulate Matter (PM) - filterable	161
Total Particulate Matter	412
Sulfur Dioxide (SO_2)	299
Nitrogen Oxides (NO_x)	629
Carbon Monoxide (CO)	920
Volatile Organic Compounds (VOC)	28
Fluorides, as hydrogen fluoride	0.613
Sulfuric Acid Mist	67
Mercury	0.0381
Hydrogen Chloride	7.45
Lead, as elemental lead	0.0196

The plant would also have the potential to emit much smaller amounts of emissions from the gasifiers and other operations at the plant. Thus, the emissions generated at the plant result primarily from the operation of the combustion turbines.

IV. APPLICABLE EMISSION STANDARDS

All emission units in Illinois must comply with state emission standards adopted by the Pollution Control Board. The state's emission standards represent the basic requirements for sources in Illinois. The various emission units in the proposed plant should readily comply with applicable state standards.

Certain emission units at the proposed plant would also be subject to federal New Source Performance Standards (NSPS), at 40 CFR Part 60. The combustion turbines and associated heat recovery steam generators are subject to the NSPS for electric utility steam generating units, 40 CFR 60, Subpart Da. The NSPS sets emission limits for nitrogen oxides, sulfur dioxide, particulate matter, and mercury emissions, as well as opacity, from the units. The plant's carbon bed and syngas cleaning system is designed to reduce mercury emissions by 95%, which should satisfy the mercury emission limit specified by Subpart Da.

The combustion turbines are also subject to NSPS for gas turbines, 40 CFR 60, Subpart GG.

The auxiliary boiler is subject to the NSPS for non-utility steam generating units, 40 CFR 60 Subpart Db. Various coal handling operations at the plant are subject to NSPS for coal preparation plants, 40 CFR 60, Subpart Y.

V. OTHER APPLICABLE REGULATIONS

A. Prevention of Significant Deterioration (PSD)

The proposed plant is a major new source subject to the federal rules for Prevention of Significant Deterioration of Air Quality (PSD), 40 CFR 52.21. Because the plant's proposed location is in an attainment area, under PSD, the proposed plant is major for emissions of NO_x, SO_2, PM and CO with potential annual emissions of more than 100 tons for each of these pollutants. Under the PSD rules, once a proposed source is major for any PSD pollutant, all PSD pollutants whose potential emissions are above the specified significant emission rates in 40 CFR 52.21(b)(23) are also subject to PSD review. Therefore, the proposed plant is also subject to PSD review for sulfuric acid mist, with potential annual emissions of 67 tons, which exceed the significant emission rate of 7 tons.

B. Maximum Achievable Control Technology (MACT)

Potential emissions of hazardous air pollutant (HAP) from the plant are less than 25 tons per year in the aggregate and less than 10 tons per year for any single HAP. Therefore, the proposed plant is not a major source of HAPs and is not subject to MACT standards, either as adopted by USEPA or as determined on a case-by-case during permitting pursuant to Section 112(g) of the Clean Air Act.

C. Acid Rain Program

The proposed plant is an affected source and the two combustion turbines/heat recovery steam generators are affected units for Acid Deposition: Title IV of the Clean Air Act, and regulations promulgated thereunder. These provisions establish requirements for affected sources related to control of emissions of SO_2 and NO_x, pollutants that contribute to acid rain. Under the Acid Rain program, Christian County Generation would have to hold SO_2 allowances for the actual SO_2 emissions from the affected units. Effectively, the Acid Rain program requires reductions in SO_2 emissions from existing coal-fired power plants elsewhere in the United States. This is because the number of SO_2 allowances issued by USEPA to coal-fired power plants annually is fixed, to meet the SO_2 emission target set by the federal Clean Air Act as related to acid rain. Another requirement of the Acid Rain program is to operate pursuant to an Acid Rain permit. The Illinois EPA is proposing to issue the initial Acid Rain permit for the proposed plant in conjunction with issuance of the construction permit for the plant.

D. Clean Air Interstate Rule

Combustion turbines used to produce electricity generally qualify as Electrical Generating Units (EGU) and are subject to 35 IAC Part 217, Subpart W, the NO_x Trading Program for Electrical Steam Generating Units. This program will have been replaced by Illinois' version of the Clean Air Interstate Rule, which will take the place of the NO_x Trading Program, before the startup of the turbines. The turbines and Christian County Generation will have to comply with the applicable requirements of Illinois' Clean Air Interstate Rule.

E. Clean Air Act Permit Program (CAAPP)

This plant would be considered a major source under Illinois' Clean Air Act Permit Program (CAAPP) pursuant to Title V of the Clean Air Act. This is because the plant would be a major source for purposes of the CAAPP because it is a major source for purposes of the above regulatory programs, most notably PSD. Christian County Generation would have to apply for its CAAPP permit within 18 months after initial startup of the plant.

VI. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Under the PSD rules, an applicant for a permit must demonstrate that Best Available Control Technology (BACT) will be used to control emissions of pollutants subject to PSD. Christian County Generation has provided a BACT demonstration in its application addressing emissions of pollutants that are subject to PSD, i.e., NO_x, SO_2, CO, PM/PM_{10} and sulfuric acid mist.

BACT is defined by the federal Clean Air Act as:

> An emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental and other costs, determines is achievable for such facility through application of production processes and available methods, systems and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.
>
> Clean Air Act, Section 169(3)

BACT is generally set by a "Top Down Process." In this process, the most effective control option that is available and technically feasible is assumed to constitute BACT for a particular unit, unless the energy, environmental and economic impacts associated with that control option are found to be excessive. This approach is generally followed by the Illinois EPA for BACT determinations. In addition to the BACT demonstration provided by an applicant in its permit application, a key resource for BACT determinations is USEPA's RACT/BACT/LAER Clearinghouse (USEPA Clearinghouse), a national compendium of control technology determinations maintained by USEPA. Other documents that are consulted include general information in the technical literature and information on other similar or related projects that are proposed or have been recently permitted. A summary of the proposed BACT Determination for this project is provided in Attachment 1.

A. BACT Discussion for selected Electrical Generation Technology and Design Feedstock:

Feedstock/Fuel and Gasification Technology Selection

The feedstock selected for the gasifiers is Illinois #6 coal. The use of GE Technologies' gasifiers and associated gasification trains is compatible with this feedstock due to its inherent fuel characteristics, such as heat rate and ash content. Integrated gasification is designed for specific purposes and feedstocks. For example, Shell gasification technology is far better suited for western U.S. and Asian coals but not well suited for eastern U.S. bituminous coals. In addition, gasification technologies designed by the same provider may vary depending on the product, whether it is electricity (IGCC), or substitute natural gas (SNG). A GE Technologies' radiant syngas cooler may be used at the IGCC plant whereas a GE Technologies' water quench system may be used at the SNG plant. This is due to the need to ensure that the syngas have certain specific characteristics for later processing of that syngas. In short, the specific gasification technology to be used is a function of the feedstock and the end product.

Christian County Generation has selected IGCC technology for the proposed plant, rather than traditional boiler-based technology. This decision does not need to be scrutinized as part of the BACT determination for the proposed plant, except as it has a role in the selection of the design coal supply for the plant. The emission levels that are achievable with IGCC technology for different pollutants are generally significantly lower than or comparable to the levels achievable with boiler-based technology. This is because the contaminants present in coal, e.g., sulfur, particulate (ash), and fluorine, are removed from a gaseous fuel stream prior to combustion, rather than from the exhaust stream after combustion, where these contaminants would be present at much lower concentrations. Accordingly, coal gasification is one of the most promising electrical generation technologies to reduce emissions and other environmental consequences from new coal-fired power plants. Coal gasification, as recognized by USEPA, USDOE and other experts, is expected to be at the heart of the future generations of clean coal plants, as gasification offers one of the most clean and versatile ways to convert coal into electricity, as well into substitute natural gas, synthetic fuel oil, and other chemical products. As the proposed plant would be developed with IGCC technology, this also provides additional support for the overall project, as the project would facilitate the continued development and commercial application of IGCC technology for generation of electricity.

B. BACT discussion for the gasification process and combustion turbines/heat recovery steam generators:

Nitrogen Oxides (NO_x)

Christian County Generation has proposed N_2 diluent injection in combination with selective catalytic reduction (SCR) as the NO_x control measures to be used on the combustion turbines.

Based on available data, the following emission control technologies were reviewed as possible control options for NO_x, in order from most effective to least effective: 1) Selective catalytic reduction (SCR), 2) Diluent injection, 3) Steam injection, 4) Selective Non-Catalytic Reduction (SNCR) and Low-NO_x burners design. Review of the USEPA Clearinghouse indicates that diluent injection is the NO_x control measure used for turbines at IGCC plants.

Selective catalytic reduction (SCR) uses a chemical reaction to remove NO_x from the exhaust gas. The reaction between gaseous NO_x and a reagent, i.e., ammonia (NH_3), as it passes through a porous ceramic bed or screen impregnated with catalyst, reduces NO_x back to N_2. This reaction, which takes place in a temperature range of 575°F to 750°F, is considered very effective in controlling NO_x. The temperature of exhaust gas from the combustion turbines will be within this temperature range, making the TEC a suitable application for SCR. SCR is a demonstrated technology for control of NO_x emissions from natural gas fired combustion turbines.

Diluent injection is a combustion control technique that reduces the production of thermal NO_x. A diluent, such as nitrogen, is injected into the combustor lowering the temperature of the combustion flame which in turn reduces the production of thermal NO_x. This is the predominant method of NO_x control for IGCC turbines firing syngas and is feasible because of the availability of nitrogen from the Air Separation Unit ("ASU").

Steam injection is another combustion control techniques used to reduce the production of thermal NO_x. Similar to nitrogen injection, steam injection involves injecting steam into the combustor to reduce the temperature of the combustion zone which reduces the production of thermal NO_x. Steam injection has been successfully used to reduce NO_x emissions from natural gas fired combustion turbines. Steam injection can cause combustion "noise" due to the increase in fuel feed rate. This noise can disrupt turbine operation (flame stability, vibration, etc.) and cause premature wear on the equipment.

SNCR is a flue gas treatment system that reduces post-combustion NO_x emissions using ammonia or urea injection, similar to SCR but without a catalyst. However, in the absence of a catalyst, higher temperatures in the range 1600 to 2000°F are required for ammonia to selectively react with nitric oxide to form molecular nitrogen and water. Maintaining the desired temperature window is, therefore, one of the most important operating and design considerations. Since SNCR does not use a catalyst, additional ammonia must be used to achieve higher levels of NO_x control, resulting in a greater potential for ammonia slip.

Low-NO_x combustors are a control technique used for natural gas fired combustion. However, this technique is not available for low-Btu syngas, as it would interfere with stable combustion.

The use of selective catalytic reduction in combination with diluent injection is considered BACT for emissions of NO_x from the combustion turbines/heat recovery steam generators when firing syngas or natural gas. The proposed BACT limit is 0.034 lb/million Btu for syngas and 0.025 lb/million Btu for natural gas, on a 24-hour rolling average basis. The format of these limits (lb million Btu (HHV) of heat input to the combustion turbines) is selected to be consistent with the format used by USEPA in the NSPS for combustion turbines/heat recovery steam generators boilers, 40 CFR 60, Subpart Da, which would be applicable to the combustion turbines/heat recovery steam generators. This same format is used in conjunction with the BACT limits described below.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (H_2SO_4)

Technically feasible SO_2 control alternatives for the proposed combustion turbines/heat recovery steam generators include coal selection and pre-treatment, pre-combustion physical or chemical absorption with flare and thermal oxidizer, wet flue gas desulfurization (WFGD) and dry scrubbing. Coal washing is not a feasible technique to reduce SO_2 and H_2SO_4 emissions within the design range of fuel for the plant which includes a maximum sulfur content of 4.8% (dry basis). Since the highest SO_2 and H_2SO_4 emission removals available are associated with pre-combustion controls, the post combustion technologies were not considered further in the BACT analysis.

The gasification process involves conversion of a coal slurry and oxygen at very high temperature and pressure into a CO and H_2 rich fuel. Byproducts that result from using high sulfur coal as a feedstock are the gaseous pollutants H_2S and COS. These pollutants are removed in a pre-combustion Acid Gas Removal ("AGR") system which provides SO_2 control for an IGCC facility. There are currently two physical absorption solvents Selexol™ and Rectisol™ and one chemical absorption solvent, MDEA, available for use at the TEC. Each of these AGR processes involves the use of a tail gas thermal oxidizer and a flare in order to minimize total emissions of acid gases.

Physical absorption methods, including Selexol™ and Rectisol™, use solvents that dissolve acid gases under pressure. The solubility of an acid gas is proportional to its partial pressure and is independent of the concentrations of other dissolved gases in the solvent. Therefore, increased operating pressures in an absorption column will facilitate the separation and removal of an acid gas like H_2S. The dissolved acid gas can then be removed from the solvent, which is regenerated, by depressurization in a stripper.

The Selexol™ process uses Union Carbide's Selexol™ solvent made of dimethyl ether or polyethylene glycol. Acid gas partial pressure separation is the key driving force for the Selexol™ process. Feed gas enters the Selexol™ plant and is cooled with water condensate being removed. The gas then flows to an absorption tower where it is introduced to the Selexol™ solvent in countercurrent flow. Acid gases in the feed gas are absorbed into the solvent, and a clean feed gas is withdrawn from the top of the absorber column. Acid gas rich solvent from the absorber is regenerated by flashing the gas at medium pressure and then reheating the gas to the solvent boiling point and stripping the solvent.

The Rectisol™ process, also a physical absorption process, uses cold methanol as the physical solvent. Feed gas entering the AGR is cooled, and trace chemical components are removed with a cold methanol pre-wash. Then, H_2S is physically absorbed from the raw gas using CO_2-rich methanol. Raw gas is removed from the top of the absorption column, with clean syngas removed from a lower point in the column. The solvent is reclaimed through pressure reduction, stripping, and re-boiling the solvent. Although Rectisol™ has not been used in an AGR serving an IGCC facility, there are no known technical limitations that would render the process technically infeasible for the TEC's AGR system.

In a chemical absorption process, acid gases in the sour syngas are removed by chemical reactions with a solvent that is subsequently separated from the gas and regenerated. In the TEC, the amine solvent considered for chemical absorption is methyldiethanolamine ("MDEA"). Amine solvents, such as MDEA, react to form a chemical bond between the acid gas and the solvent in an absorption tower. The solvent is then reclaimed through the use of a heating process in a stripper tower. This heat stripping process produces regenerated MDEA and a concentrated H_2S stream which is then directed to the sulfur recovery process. Chemical absorption has been successfully used at existing gasification facilities to reduce the sulfur content of syngas and is a feasible technical option to serve the TEC.

The most effective SO_2 pre-combustion control systems that are technically feasible for the proposed IGCC gasification trains are physical absorption AGR systems, using either Selexol™ or Rectisol™ solvents. Both systems are capable of removing over 99% of the sulfur compounds from the syngas based on feasibility studies performed by vendors with Selexol™ achieving 99.8% removal and Rectisol™ possibly reaching 99.9% removal. Christian County Generation has selected the Selexol™ system for use at the TEC to reduce emissions of the SO_2 and H_2SO_4. Since Rectisol™ has the potential to more effectively reduce SO_2 emissions and acid gases, Christian County Generation conducted an evaluation of the economic, energy and environmental impacts associated with both the Selexol™ system and the Rectisol™ system. That evaluation supports the use of the Selexol™ system.

Christian County Generation is proposing to use the Selexol™ system with flare and thermal oxidizer as its means to reduce post-combustion generation of SO_2 and H_2SO_4 emissions in the pre-combustion control system. When firing syngas in the combustion turbines, BACT is proposed to be set at 0.016 lb SO_2/million Btu based on a 3-hour rolling average with an H_2SO_4 limit of 0.0035 lb/mmBtu based on a 3-hour rolling average. When firing natural gas, BACT is proposed to be set at 0.001 lb SO_2/million Btu based on a 3-hour rolling average. These emission limitations represent removal efficiencies greater than 99% and are more stringent than the emission limits achieved in practice at currently operating IGCC units.

Particulate Matter (PM)

There are two waste streams from which particulate matter is generated in the gasification process, namely, from coarse slag and fine slag. The coarse slag, which makes up the majority of the particulate matter, is the heavier mineral and ash matter that is not entrained in the syngas and is captured within the gasifier. The fine slag is comprised of unreactive mineral compounds and particles of feedstock that are not completely gasified (including ungasified carbon). This material is carried from the gasifier with the existing syngas and must be removed prior to the acid gas removal system.

IGCC pre-combustion syngas scrubbing, a post-combustion baghouse, and use of a post-combustion electrostatic precipitator (ESP) in combination with a wet electrostatic precipitator (WESP) have the highest control efficiencies of any of the particulate matter control options that are technically feasible for the TEC.

All existing and proposed IGCC generation projects to date have employed or propose to employ pre-combustion scrubbing as particulate control. There are two types of pre-combustion control that have been used. Each process results in similar reductions and is more a function of the gasification process selected than the results obtained. The first process is a scrubbing control technique that uses water to remove fine particulates from the syngas. The second process is a particulate filtering process similar to that of a baghouse or fabric filter, which is discussed in the subsection on fabric filters below.

In the wet scrubbing process the feed gas from the gasifier is sent to the scrubber, where water enters the chamber through spray nozzles at the top of the chamber and contacts the feed gas rising from the bottom. By operating in this counter flow manner the contact between the water and gas is maximized, resulting in significant transfer of fine particulates and water soluble contaminants to the wash stream. Particulate-laden water is then sent to a "black" water handling system, which separates the solids for recycle back to the gasifier. Pre-combustion syngas scrubbing has been shown to significantly reduce particulate emissions when firing coal derived syngas. This is supported by information contained in the Polk Power Station IGCC final project report, which indicates that the wet scrubbing effectively removes not only particulate but also HCl, ammonia and similar soluble pollutants. The report also states that in some instances particulate emissions resulting from pre-combustion syngas scrubbing are only 5% of those for a typical coal fired boiler using an ESP.

A baghouse removes particulates by drawing the dust-laden air through a bank of filter tubes suspended in the gas flow stream. A filter "cake", composed of captured particulate, builds up on the "dirty" side of the filter. Periodically, the cake is removed through a physical mechanism (e.g., a blast of compressed air from the "clean" side of the filter), which causes the cake to fall. The dust is then collected in a hopper and eventually removed.

IGCC pre-combustion syngas filtering uses hot, dry barrier filters. These barrier filters are either ceramic or metallic candle filters which are normally located upstream of the high temperature heat recovery devices. Use of candle filters produces a dry solid as opposed to the wet system discussed previously. The overall particulate control resulting from candle filters is estimated to be essentially the same as using wet scrubbers. However, the candle filters are subject to blinding or breakage as discussed in several of the status reports for the Wabash IGCC demonstration project. The dry system is also not as effective at removing chlorides as are wet scrubber systems. Chloride removal is important in minimizing potential poisoning of the hydrolysis catalyst and metallurgy degradation in downstream equipment.

ESPs remove aerosol and particulate matter from exhaust gas streams by means of electrostatic attraction. Particles in the gas stream are negatively charged by discharge electrodes located in the ESP. Once the particles are negatively charged, they migrate toward the grounded collection plates in the ESP, which have been positively charged. The particulate continues to accumulate on the collection plate until it is removed. The particulate is removed from the plates by mechanically rapping the dry ESP collection plates. The particulate (ash) falls by gravity into a hopper for disposal. ESPs have the ability to handle large gas streams and high particulate loading with very few complications and restrictions. ESPs also have a broad operating range and can be utilized at high temperature and pressure conditions, as well as with high or low-sulfur content streams.

WESPs operate in much the same way as dry or standard ESPs - charging, collecting and then cleaning. The difference between the two lies in the cleaning step. WESP cleaning is performed by washing the collection surfaces with water, in lieu of the usual mechanical means such as rapping of the collection plates. The delivery of the liquid or water can be made by a series of spray nozzles located in the control device or by condensing moisture from the flue gas on the collection surfaces. WESPs are able to control a larger variety of pollutants than an ESP alone.

Because candle filters are capable of achieving particulate control potentially equivalent to that of wet scrubbing, they were rejected due to the potential for blinding and breakage that may occur, resulting in potential malfunctions and operational downtime. Similarly, traditional particulate controls (e.g. baghouses, fabric filters, ESP and WESP) are not demonstrated or available in any current gasification design. Christian County Generation has therefore selected pre-combustion IGCC wet syngas scrubbing as BACT for controlling PM/PM_{10}.

Christian County Generation is proposing a PM/PM_{10} BACT emission limitation of 0.009 lb/mmBtu filterable and 0.022 lb/mmBtu total (filterable and condensable) when firing syngas based on a 3-hour rolling average. Christian County Generation is also proposing a PM/PM_{10} BACT emission limitation of 0.007 lb/mmBtu filterable and 0.011 lb/mmBtu total (filterable and condensable) when firing natural gas, based on a 3-hour rolling average. These emission limitations represent a removal efficiency exceeding 99.9% and are more stringent than the PM_{10} emission limit achieved in practice at currently operating IGCC units and the lowest proposed PM_{10} emission limit for any proposed coal-fired unit.

Carbon Monoxide (CO)

Carbon monoxide (CO) emissions are the product of incomplete combustion. The control methods are 1) Excess air and 2) Design of the combustion process and good combustion practices to minimize the formation of CO. A large amount of excess air in the combustion turbines could theoretically reduce CO emissions by raising the amount of oxygen available to provide complete oxidation of CO to CO_2. Use of this technique would have the adverse environmental impact of increasing emissions of other pollutants, particularly thermal NO_x, which is supported by excess air.

Christian County Generation proposes proper operation and maintenance in combination with a CO emission limit of 0.049 lb/million Btu based on a 24-hour rolling average when firing syngas and 0.045 lb/million Btu, based on a 24-hour rolling average when firing natural gas, to be BACT for the combustion turbines. This is supported by recent permits and applications for IGCC projects.

C. BACT Discussion for the Auxiliary Boiler

For the auxiliary boiler, natural gas is identified as the sole fuel, the annual hours of operation are constrained to 500 hours, and low-NO_x burners are proposed. BACT for the boiler was determined to be the use of Low-NO_x burners.

D. BACT Discussion for the Cooling Tower

High-efficiency drift eliminators and dry cooling were considered for controlling PM emissions from the cooling tower. Direct dry cooling systems use air to directly condense steam, whereas indirect dry systems use a closed loop water system to condense steam and the resulting heated water is then air cooled. Such dry cooling systems tend to transfer heat to the atmosphere without significant loss of water. On the other hand, these systems require a large amount of power to operate the many fans needed to move the air flowing through the unit. There is also a consequential noise problem associated with these fans. The extra equipment needed and the 12% increase in electricity required to operate that equipment renders dry cooling too cost-ineffective to use, relative to the use of wet cooling. As a result, the use of high-efficiency drift eliminators are proposed for the cooling tower.

E. BACT Discussion for Material Handling

Particulate emission control from coal and slag handling will be effectively controlled in a variety of ways. These include use of baghouses and implementation of other control measures to effectively control process particulate matter and fugitive dust emissions from handling of fine material with the potential to generate dust. Fugitive dust control will encompass a variety of suppression or elimination techniques including partial or total enclosure and compaction and/or chemical or wet suppression (storage piles).

F. BACT Discussion for Roadways and Open Areas

Because the proposed plant is being developed to receive coal by rail, the majority of road traffic will be associated with on-site disposal of slag and the activities of employees.

Fugitive dust control will encompass a variety of suppression or elimination techniques including paving (roadways), dust suppression, sweepers and vacuum trucks.

G. BACT Discussion for Backup and Emergency Engines

For the emergency fire pump, natural gas is identified as the sole fuel and operation is limited to 500 hours annually. For the fuel utilized in the engine and minimal emissions subsequently generated, controlling emissions would not be cost effective.

VII. AIR QUALITY ANALYSIS

A. Introduction

The previous discussions addressed emissions and emission standards. Emissions are the quantity of pollutants emitted by a source, as they are released to the atmosphere from various emission units. Standards are set limiting the amount of these emissions as a means to address the presence of contaminants in the air. The quality of air as we breathe it or as plants and animals experience it is known as ambient air quality. Ambient air quality considers the emissions from a particular source after they have dispersed following release from a stack or other emission point, in combination with pollutants emitted from other nearby sources and background pollutant levels.

The concern for pollutants in ambient air is typically expressed in terms of the concentration of the pollutant in the air. One form of this expression is parts per million. A more common scientific form is microgram per cubic meter, which is a millionth of a gram in a cube of air one meter on a side.

The United States EPA has established standards for the level of various pollutants in the ambient air. These ambient air quality standards are based on a broad collection of scientific data to define levels of ambient air quality where adverse human health impacts and welfare impacts may occur. As part of the process of adopting air quality standards, the USEPA compiles scientific information on the potential impacts of the pollutant into a "criteria" document. Hence the pollutants for which air quality standards exist are known as criteria pollutants. Based upon the nature and effects of a pollutant, appropriate numerical standards(s) and associated averaging times are set to protect against adverse impacts. For some pollutants several standards are set, for others only a single standard has been established.

Areas can be designated as attainment or nonattainment for criteria pollutants, based on the existing air quality. Areas in which the air quality standard is met for a pollutant are known as attainment areas. If the air quality standard is exceeded, the area is designated as nonattainment. Given the geographic extent of areas designated as nonattainment and the USEPA's process for redesignating an area to attainment, the air quality in some or all of an area designated as nonattainment may actually be in compliance with the relevant air quality standard.

In attainment areas the goal is to generally preserve the existing clean air resource and prevent increases in emissions which would result in nonattainment. In a nonattainment area efforts must be taken to reduce emissions to come into attainment. An area can be attainment for one pollutant and nonattainment for another.

Compliance with air quality standards is determined by two techniques, monitoring and modeling. In monitoring one actually samples the levels of pollutants in the air on a routine basis. This is particularly valuable as monitoring provides data on actual air quality, considering actual weather and source operation. The Illinois EPA operates a network of ambient air monitoring stations across the state.

Monitoring is limited because one cannot operate monitors at all locations. One also cannot monitor to predict the effect of a future source, which has not yet been built, or to evaluate the effect of possible regulatory programs to reduce emissions. Modeling is used for these purposes. Modeling uses mathematical equations to predict ambient concentrations based on various factors, including the height of a stack, the velocity and temperature of exhaust gases, and weather data (speed, direction and atmospheric mixing).

Modeling is performed by computer, allowing detailed estimates to be made of air quality impacts over a range of weather data. Modeling techniques are well developed for essentially stable pollutants like particulate matter, NO_x, and CO, and can readily address the impact of individual sources. Modeling techniques for reactive pollutants, e.g., ozone, are more complex and have generally been developed for analysis of entire urban areas. They are not applicable to a single source with small amounts of emissions.

Air quality analysis is the process of predicting ambient concentrations in an area or as a result of a project and comparing the concentration to the air quality standard or other reference level. Air quality analysis uses a combination of monitoring data and modeling as appropriate.

B. Air Quality Analysis for NO_2, SO_2, PM_{10} and CO

An ambient air quality analysis was conducted by a consulting firm, Kentuckiana Engineering, on behalf of Christian County Generation to assess the impacts of the proposed plant on ambient air quality. Under the PSD rules, this analysis must demonstrate that the proposed project will not cause or contribute to a violation of any applicable air quality standard or PSD increment.

The starting point for determining the extent of the modeling necessary for this facility was evaluating whether the proposed plant would have a "significant impact". The PSD rules identify

Significant Impact Levels, which represent thresholds triggering a need for more detailed modeling. These thresholds are specified for all criteria pollutants, except ozone and lead. The significant impact levels do not correlate with health or welfare thresholds for humans, nor do they correspond to a threshold for effects on flora or fauna. For pollutants for which impacts were above the significant impact level, modeling was done incorporating proposed new emissions units at the proposed plant and significant stationary sources in the surrounding area.

The Illinois EPA performed selected audit modeling runs to verify the applicant's results for the preliminary impact analysis and full impact analysis. The accompanying tables (Tables 1 - 4) summarize the results.

TABLE 1

PRELIMINARY IMPACT ANALYSIS
(SIGNIFICANT IMPACT ASSESSMENT)

Pollutant	Averaging Period	Significant Impact Increment ($\mu g/m^3$)	National Ambient Air Quality Standard (NAAQS) ($\mu g/m^3$)	Maximum Modeled Concentration[a] Per Applicant ($\mu g/m^3$)
NO_x	Annual	1	100	0.66
SO_2	3-Hour	25	1,300	38.00
	24-Hour	5	365	8.90
	Annual	1	80	0.35
PM_{10}	24-Hour	5	150	25.77
	Annual	1	50	1.22
CO	1-Hour	2,000	40,000	115.40
	8-Hour	500	10,000	51.16

Notes:

a. High 1st high value based upon individual evaluation of each year of a 5-year meteorological dataset.

The preliminary impact analysis showed maximum concentrations for PM_{10} (24-hour and annual) and SO_2 (3-hour and 24-hour average only) that are greater than applicable significant impact levels. This triggered further analysis with modeling of both the proposed plant and existing sources in the area. Consideration was also given to the background levels of air quality, as determined at ambient monitoring stations operated by the Illinois EPA. This full impact analysis yielded concentrations that were in compliance with the PSD increments as is demonstrated in Table 2 below and the NAAQS standards as depicted in Table 3.

TABLE 2

PSD CLASS II INCREMENT CONSUMPTION MODELING RESULTS

Pollutant	Averaging Period	Class II PSD Increments ($\mu g/m^3$)	Maximum Concentration Per Applicant ($\mu g/m^3$)
SO_2	3-Hour	512	38.00[a]
	24-Hour	91	8.90[a]
PM_{10}	24-Hour	30	14.82[a]
	Annual	17	1.26[b]

Notes

a. High 2nd high value based upon individual evaluation of each year of a five year meteorological dataset.

b. High 1st high value based upon individual evaluation of each year of a five year meteorological dataset.

TABLE 3

NAAQS MODELING RESULTS

Pollutant	Averaging Period	NAAQS ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Maximum Modeled Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)
SO_2	3-Hour	1300	330.12[a]	408.16[b]	738.28
	24-Hour	365	115.28[a]	85.29[b]	200.57
PM_{10}	24-Hour	150	53[a]	76.53[c]	129.53
	Annual	50	22.97[a]	5.06[d]	28.03

Notes

a. Highest concentration for the Sangamon ambient air quality monitor (2003/2004) for SO_2 and the Macoupin ambient air quality monitor (2003/2004) for PM_{10}.

b. High 2nd high value based upon individual evaluation of each year of a 5-year meteorological dataset.

c. High 6th high value based upon individual evaluation of each year of a 5-year meteorological dataset.

b. High 1st high value based upon individual evaluation of each year of a 5-year meteorological dataset.

C. Air Quality Analysis for Hazardous Air Pollutants (HAPs)

Christian County Generation also submitted an air quality impact analysis for emissions of HAPs from the proposed plant. HAP modeling results (24-hour average impacts for mercury, beryllium, and fluorides) were evaluated by comparing them against monitoring de minimus levels. This analysis used meteorological data for 1986, 1987, 1989, 1990 and 1991 like the analysis for criteria pollutants.

TABLE 4

HAP MODELING RESULTS AND DE MINIMUS MONITORING LEVELS

Receptor		Fluorides		Mercury		Beryllium	
x-utm (m)	y-utm(m)	Maximum Concentration[a] (ug/m^3)	Monitoring DeMinimus (ug/m^3)	Maximum Concentration[a] (ug/m^3)	Monitoring DeMinimus (ug/m^3)	Maximum Concentration[a] (ug/m^3)	Monitoring DeMinimus (ug/m^3)
315,415.59	4,384,894.50	0.0104	0.25	0.00137	0.25	0.0000695	0.001

Notes

a. Highest 2nd high concentration. For all pollutants, meteorological data for 1986 produced the highest 2nd high concentration.

D. Vegetation and Soils Analysis

Christian County Generation provided an analysis of the impacts of the proposed plant on vegetation, animals, and soils, and on emissions impacts resulting from residential and commercial growth associated with construction of the proposed plant ("additional impact analysis").

The first several steps in this process focus on the use of modeled air concentrations and published screening values for evaluating exposure to flora from selected criteria pollutants (SO_2, NO_x, CO, ozone and PM_{10}). These screening values or threshold ambient concentrations (which may indicate levels of potential adverse impacts) are provided for "sensitive", "intermediate", and "resistant" species. The applicant has conservatively compared maximum modeled concentrations against "sensitive" species threshold concentrations, and in all instances, modeled impacts are below the "sensitive" value thresholds.

Potential adverse impacts to soil and biota from deposition of hazardous air pollutants (trace elements including hazardous metals) are the focus of the methodology. In this stepwise process, soil (depositional) loadings calculated from annual average air concentrations (modeling results) are combined with published endogenous soil concentration data and compared against threshold impact information. Dispersion modeling results were obtained for short- and long-term averaging periods for arsenic, cadmium, cobalt, selenium, chromium, fluoride, lead, manganese, mercury, and nickel. Annual average concentrations were converted to deposited soil concentrations and plant tissue concentrations and compared against screening levels for soil, plant tissue, and dietary intake (animals). In all cases, the pollutant levels were less than the screening levels.

The proposed plant's emissions are not expected to result in harmful effects to the soils and vegetation in the area. Maximum modeled impacts for SO_2, NO_x, CO and PM_{10} do not exceed the secondary NAAQS level set forth by USEPA. Maximum modeled 3-hour average SO_2 impacts do not exceed the significant impact level for the secondary standard.

Discussions between the Illinois EPA and the Illinois Department of Natural Resources, as required under Illinois' Endangered Species Act, are ongoing, to review the above conclusions with respect to species of vegetation that are endangered. These discussions also address endangered species of animals that may be present in the area.

E. Construction and Growth Analysis

Christian County Generation provided a discussion of the emissions impacts resulting from residential and commercial growth associated with construction of the proposed plant ("additional impact analysis"). Anticipated emissions resulting from residential, commercial, and industrial growth, associated with construction and operation of the proposed plant, are expected to be low. Despite the large number of workers required during the construction phase and a significant number of permanent employees for operation of the plant, emissions associated with new residential construction, commercial services, and supporting secondary industrial services are not expected to be significant. To the extent that the plant draws from the existing work force and is supported by the existing infrastructure, impacts would be minimal and distributed throughout the region.

F. Environmental Assessment

Illinois law does not provide for performance of other environmental impact assessments in conjunction with the issuance of this permit for the proposed plant. Likewise, the issuance of this permit is not a federal action for which an Environmental Impact Assessment would be required under the National Environmental Policy Act.

VIII. DRAFT PERMIT

The Illinois EPA has prepared a draft of the construction permit that it would propose to issue for the plant. The permit is intended to identify the applicable rules governing emissions from the plant and to set limitations on those emissions. The permit is also intended to establish appropriate compliance procedures to accompany those requirements, including requirements for emissions testing, continuous emissions monitoring, record keeping, and reporting.

IX. REQUEST FOR COMMENTS

It is the Illinois EPA's preliminary determination that the draft permits would meet all applicable state and federal air pollution control requirements, subject to the conditions in the draft permit.

RPS:05040027:psj

Attachment 1 - Summary of Proposed BACT Determinations

Gasifiers with Flare and Sulfur Plant:

Pollutant	Principal Control Measures	Limit
Sulfur Recovery Unit		
SO_2	Acid gas removal by physical adsorption with Selexol process	100 ppm by volume (dry basis) at 0% oxygen, 3-hour average
Flare		
All Pollutants	Good combustion practices	------

Combustion Turbines(CTs)/Heat Recovery Steam Generators (HRSGs):

Pollutant	Principal Control Measures	Limit
PM/PM_{10} Filterable	Syngas cleaning	0.009 lb/million Btu, 3-hour ave.
PM_{10} Total	Syngas cleaning	0.022 lb/million Btu, 3-hour ave.
SO_2	Syngas cleaning (Acid gas removal by physical adsorption with Selexol process)	0.016 lb/million Btu, 3-hour ave.
NO_x	SCR and diluent nitrogen injection.	0.034 lb/million Btu, 24-hour ave.
CO	Good combustion practices	0.049 lb/million Btu, 24-hour ave.
Sulfuric Acid Mist	Syngas cleaning (Acid gas removal by physical adsorption with Selexol process)	0.0035 lb/million Btu, 3-hour ave.

Auxiliary Boiler:

Pollutant	Control Measures	Limitation
PM	Natural gas fuel	0.007 lb/million Btu
NO_x	Low-NO_x burners	0.036 lb/million Btu
SO_2	Natural gas fuel	0.006 lb/million Btu
CO	Good combustion practices	0.037 lb/million Btu

Material Handling Operations:

Emission Unit	Control Measures	Limitation
Material Processing, Transfer Buildings, and Handling Operations	Enclosures, baghouses or vent filters, use of dust suppressants	-----
Coal Storage Pile Load in and Maintenance Activity	Compaction Suppressants Reduced Drop Heights Stacking Tubes Use of Dust Suppressants	-----

Other Operations:

Emission Unit	Control Measures	Limitation
Cooling Tower	0.0005% Drift Eliminators	-----
Slag Landfill Plant Roadways and Open Areas	Paved Roads where practicable, dust control program	-----

Attachment 2 - Detailed Description of the Integrated Gasification Combined Cycle (IGCC) technology at the Proposed Plant

The core of the proposed plant is the production of syngas in the gasification block. The gasification block at TEC will have three gasifiers, each unit designed to produce 50% of the raw syngas required for the plant when operating at maximum load. The third gasifier allows for continued syngas supply and operation of the plant at capacity during periods of gasifier maintenance or other gasifier outages, which reduces concerns regarding gasifier reliability. The key components of the gasification block are as follows:

Process	Sub-Process	Control Measures
Gasifiers	Normal operation	Not applicable
	Startup, shutdown and upset	Flare
Syngas Clean-up	Mercury removal - carbon bed	Not Applicable
	Particulate removal - Water scrubbing	
	Acid gas removal - scrubbing with Selexol process	
Support Facilities.	Sulfur recovery plant	Tailgas treatment and thermal oxidizer
	Air separation unit (ASU)	

The gasifiers will operate using the General Electric oxygen-blown, entrained flow process. This process includes coal slurry and oxygen feed systems, gasifier reaction chambers, and syngas cooling. The coal feedstock is fed to the gasifiers through a process feed injector that mixes the coal slurry and oxygen to optimize dispersion into the gasifier. A proper blend of feedstock and oxygen is important to the efficient operation of the gasifiers. The slurry and oxygen feeds to the injector are controlled by a series of valves to facilitate safe shutdown in case of upsets.

The gasifiers are designed to operate at high pressure and at temperatures between 2300° and 2700°F. The gasifiers operate in an oxygen deficient mode to facilitate the physical processes and chemical reactions which produce the syngas, rather than combust the coal. The syngas is principally hydrogen and carbon monoxide. The gasifiers also generate two byproducts from the coal, a coarse vitreous slag, which comes out the bottom of the gasifiers, and a fine slag, which is entrained in and carried out with the syngas.

When the syngas leaves the gasifier it first passes through a heat exchanger, the Radiant Syngas Cooler (RSC), that uses the high temperature of the syngas leaving the gasifiers to produces high pressure steam. This increases the efficiency of the plant by recapturing up to 15% of the heating value of the coal feedstock. Prior to leaving the gasifier, syngas contacts a water pool (quench section) located at the bottom of the unit which enhances collection of the slag.

The syngas from the gasifiers has a heat content of approximately 250 Btu per standard cubic foot and is composed mainly of hydrogen (H_2), carbon monoxide (CO), water vapor (H_2O) and carbon dioxide (CO_2). The syngas also contains lesser amounts of several components such as hydrogen sulfide (H_2S), carbonyl sulfide (COS), methane (CH_4), and nitrogen (N_2). It also contains entrained fine slag that would be emitted as particulate matter if the raw gas were burned. Because of undesirable components such as H_2S, COS, and fine slag, raw syngas produced by the gasifiers must undergo cleanup prior to use as fuel in the combustions turbines. Removal of these components is done using several gas cleaning techniques.

Fine slag is comprised of unreactive mineral compounds and particles that are not completely gasified (unburned carbon). This material is carried from the gasifier with the raw syngas and must be removed prior to entering the Acid Gas Removal ("AGR") system. The syngas is scrubbed with water to remove entrained particulate. It is during this scrubbing step that the hydrogen chloride (HCl), which is formed from the chlorine contained in the coal, is removed. The dirty or "black" scrubbing water is flashed to lower temperature and pressure and concentrated in the fine slag handling section. This concentrated slurry is then recycled to the coal grinding and feed system.

Slag is the mineral and ash matter that does not convert to syngas and is too heavy to be transported by the existing syngas. A portion of this material melts in the high temperatures of the gasifier and flows to the bottom of the gasifier. It is removed from the gasifier through a lock-hopper. The slag is then transported to the slag handling operations. The slag solidifies into a stable glassy frit with very small amounts of residual carbon. The slag is dewatered and transported by truck for sale as a by-product or to an onsite landfill for storage.

The saturated syngas exiting the scrubber is then sent to the COS hydrolysis reactor. A small percentage of the sulfur in the coal slurry is converted to carbonyl sulfide (COS) during gasification. The acid removal system is unable to remove COS from the syngas, so COS is first converted into a chemical form that can be removed. Using a superheater followed by a catalyst reactor, conversion of COS to H_2S is possible by the following chemical reaction. By converting the COS to H_2S the system is able to remove in excess of 99% of the SO_2 producing pollutants from the syngas using the AGR system.

$$COS + H_2O \rightarrow H_2S + CO_2$$

The syngas exiting the COS hydrolysis reactor passes through a series of heat exchangers called the Low Temperature Gas Cooling (LTGC) system. These exchangers are used to remove the process condensate as the gas is conditioned for H_2S removal. The syngas enters the LTGC and is cooled to near ambient temperature prior to entering the mercury removal section. The cooled syngas passes through a carbon bed which removes the mercury as well as other trace pollutants from the coal. After passing through the carbon bed the syngas is transferred to the Acid Gas Removal (AGR) system.

The cooled syngas from the mercury removal system still contains high levels of H_2S which must be removed prior to being combusted in the combustion turbines. The syngas is sent to a Selexol™ AGR system to remove the H_2S. The Selexol™ process uses Union Carbide's Selexol™ solvent made of dimethyl ether or polyethylene glycol. Acid gas partial pressure separation is the key driving force for the Selexol™ process. Syngas enters the Selexol™ plant and is cooled with water condensate being removed. The gas then flows to an absorption tower where it is introduced to the Selexol™ solvent in countercurrent flow. Acid gases in the feed gas are absorbed into the solvent, and a clean feed gas is withdrawn from the top of the absorber column. Acid gas rich solvent from the absorber is regenerated by flashing the gas at medium pressure and then reheating the gas to the solvent boiling point and stripping the solvent.

The clean syngas exiting the absorber passes through a knockout drum and demister to remove any entrained solvent. The syngas is then preheated by passing through the highest temperature LTGC exchanger. The syngas leaves the LTGC exchanger and is sent to the combustion turbines.

The plant is being designed with one flare for the gasification block. The flare will be used to burn non-specification syngas during unit startup, or on-spec syngas during short-term outages of a combustion turbine. All flared syngas will have been treated by the mercury removal and AGR systems prior to flaring. The flare will not operate during normal operation of the gasifiers.

Oxygen for the gasifiers is produced at the plant in an Air Separation Unit (ASU). The ASU use very cold refrigeration to separate ambient air into oxygen (O_2)and nitrogen (N_2). The oxygen stream is in excess of 95% purity (95% O_2 and 5 % N_2), as required for efficient production of syngas in the gasifiers. The nitrogen stream is also used in the combustion turbines, recovering the pressure energy. As the nitrogen also serves as combustion diluent, it also assists in controlling the NO_x emissions from the combustion turbines.

The H_2S captured in the AGR, is sent to the sulfur recovery system where elemental sulfur is recovered in a Claus process and the remaining tail gas is sent to a tail gas treatment unit where additional sulfur is recovered and the overhead gas is destroyed by thermal oxidation. The recovered sulfur is a saleable byproduct and is processed for offsite use.

RPS:05040027:psj

217/782-2113 CERTIFIED MAIL

NOTICE OF ADDITIONAL CONSTRUCTION PERMIT APPLICATION FEES

September 14, 2006

Christian County Generation, LLC
Attn: Mike McInnis
4350 Brownsboro Road, Suite 110
Louisville, Kentucky 40207

Application No.:	05040027
I.D. No.:	021060ACB
Applicant's Designation:	IGCC
Date Received:	April 14, 2005
Construction of:	IGCC Plant
Location:	1630 N. 1400 E. Road, Taylorville
Additional Fee Now Due:	$1,000.00

This letter provides written notice that the Illinois EPA has determined that the application for construction permit referenced above is subject to additional application fees under Section 9.12 of Illinois' Environmental Protection Act (Act).

Based on its initial review of the application for purposes of fees, the Illinois EPA has determined that an additional fee of $1,000.00 is due.

You have 60 days to remit the assessed fee and revised Form 197-FEE to the Illinois EPA. Please submit payment to the Illinois EPA at the following address. Make either a check or money order payable to: "Illinois Environmental Protection Agency" and reference both the application and I.D. numbers assigned above. The Illinois EPA will not accept cash payments.

Illinois Environmental Protection Agency
Division of Air Pollution Control
Permit Section (MC 11)
P.O. Box 19506
Springfield, Illinois 62794-9506

If the additional fee is not submitted within 60 days, the Illinois EPA is not required to further review or process this application and the statutory deadlines in Section 39(a) of the Act cease to apply to the application until such time as the proper fee is submitted. The Illinois EPA may also deny the application for failure to pay the appropriate fees. Also, please be aware that the Illinois EPA's continuing review of the application during this 60-day period may identify additional fees that are due or deficiencies in the technical information that has been submitted in the application.

The following explains the Illinois EPA's determination with respect to the fees that are due for this application. The fee for seven or more emission units at a major source is $10,000.00 (Line 17), minus $9,000.00 already paid for the proposed units, equals $1,000.00 due.

If you do not agree with the Illinois EPA's fee determination for this application, you may ask for reconsideration. A request for fee reconsideration must include a new certified estimate (e.g., Form 197-FEE) of the fees that are due and payment for any additional fees that are due based on your new estimate. Two copies of this fee reconsideration request must be submitted and must include any supporting material used in the new estimate. On all submittals, please reference both the application and I.D. numbers assigned above.

If you have any questions on this fee determination, please call Bob Smet at 217/782-2113.

Donald E. Sutton, P.E.
Manager of Permit Section
Division of Air Pollution Control

DES:RPS:psj

cc: Illinois EPA, FOS Region 2
Paulette Blakes

217/782-2113 CERTIFIED MAIL

REQUEST FOR ADDITIONAL INFORMATION

October 6, 2005

Christian County Generation, LLC
Attn: Michael L. McInnis
4350 Brownsboro Road, Suite 110
Louisville, Kentucky 40207

Application No.:	05040027
I.D. No.:	021060ACB
Applicant's Designation:	IGCC
Received:	April 14, 2005
Construction of:	Integrated Gasification Combined-Cycle Power Plant
Location:	1630 North 1400 E Road, Taylorville

The application for construction permit referenced above lacks information necessary to determine compliance of your proposed source with 40 CFR 52.21.

The application cannot be fully evaluated until the following information is supplied:

1. Although no contracts have been signed between Christina County Generation LLC (CCG) and the nearby Christina County Coal Mine (Mine) for its coal supply, provide the air quality modeling data for the expected emissions from the mine. Given that the mine is currently the most likely candidate for supply coal to CCG, the Illinois EPA will assume a future relationship between CCG and the Mine, for purposes of permitting and air quality effects, the absence of any information otherwise.

2. In the event that chemicals production at the proposed plant will occur in the future. Explain how BACT might differ from that being proposed currently.

3a. For any technically feasible BACT candidate that is more effective in reducing emissions than the selected BACT technology for add-on control, to justify exclusion of that other BACT candidate based on its economic impacts, provide the costs associated with that technology with supporting documentation using the USEPA's guidance for estimating costs. Also, include cost data for the following:

   i. Use of Selective Catalytic Reduction for the control of NO_x on the Combustion Turbines.

b. For the candidate control technologies addressed above, calculate average cost-effectiveness and justify use of incremental costs rather than average costs, if exclusion of a technology is based on incremental cost-effectiveness.

4. Justify the use of the chosen averaging times for the emissions from the combustion turbines. Justify, in particular, the use of 30-day averaging.

Failure to supply this information by June 15, 2005 may require the Illinois EPA to deny this permit application. Two copies of this information are required and will serve as a supplement to your application. Please reference the application and I.D. numbers assigned above on any submission of additional information or any correspondence concerning this matter.

Please note that further information may be required when the Illinois EPA completes its review of the requested information.

This letter does not address matters related to the air quality modeling and analysis contained in the application, for which the Illinois EPA's initial review is still ongoing.

If you have any questions concerning this letter, please contact Bob Smet at 217/782-2113.

Donald E. Sutton, P.E.
Manager, Permit Section
Division of Air Pollution Control

DES:RPS:psj

Attachment

cc: Region 3