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MEMORANDUM OF UNDERSTANDING

BETWEEN NRDC AND NRECA

February 2008

America has abundant opportunities to save energy more cheaply than it can be produced. America's electric cooperatives can play a vital role in exploiting such opportunities as part of their core responsibility to build resource portfolios that minimize the cost of the reliable energy services on which healthy economies depend. And energy efficiency can be a uniquely productive way to reduce pollution from all sources without raising electric bills.

In aid of our joint commitment to cost-effective energy efficiency as a resource opportunity for America's electric cooperatives, we undertake as follows:

1. We will work together to identify and support cost-effective improvements in minimum efficiency standards for buildings and equipment at both state and federal levels;
2. We will coauthor a joint review of rate-setting strategies for ensuring that large-scale, cost-effective energy efficiency improvements will advance the financial interests of both electric cooperatives and their members, and we will aim to include specific joint recommendations for consideration by co-op boards and management;
3. We will begin a mutual effort to strengthen the nation's energy-efficiency infrastructure, including but not limited to
    - Expanding the involvement of NRECA and its members in regional and national energy efficiency alliances;
    - Creating an energy efficiency center within NRECA itself to help members pool their resources and take advantage of best practices throughout the electric cooperative community;
    - Supporting the establishment and expansion of academic centers on energy efficiency at colleges and universities across the nation, to help accelerate technology innovation, improve program design and train efficiency experts.

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BEFORE THE OFFICE OF STATE ADMINISTRATIVE HEARINGS
STATE OF GEORGIA

FRIENDS OF THE CHATTAHOOCHEE, INC. and SIERRA CLUB, Petitioners, v. DR. CAROL A. COUCH, DIRECTOR, ENVIRONMENTAL PROTECTION DIVISION, GEORGIA DEPARTMENT OF NATURAL RESOURCES, Respondent, and LONGLEAF ENERGY ASSOCIATES, LLC, Intervenor.	:	Docket No.: OSAH-BNR-AQ-0732139-60-Howells

MEMORANDUM OPINION AND ORDER ON MOTIONS FOR SUMMARY DETERMINATION

Introduction

On May 14, 2007, Dr. Carol A. Couch, Director of the Environmental Protection Division ("EPD") of the Georgia Department of Natural Resources ("Respondent") issued a Prevention of Significant Deterioration ("PSD") Air Quality Permit No. 4911-099-0030-P-01-0 ("Permit") to Longleaf Energy Associates, LLC ("Intervenor").[1] (Pet., Ex. A). The Permit authorizes Intervenor to construct and operate a 1,200 megawatt coal fired electric generating station. On June 13, 2007, Petitioner, Friends of the Chattahoochee, Inc. ("FOC") and Petitioner,

[1] *Available at* http://www.georgiaair.org/airpermit/psd/dockets/longleaf/permitdocs/0990030final.pdf (last visited November 20, 2007).

Sierra Club, hereinafter "Petitioners," filed a Petition for Hearing ("Petition") to appeal Respondent's decision to issue the Permit.[2]

Procedural Background

On July 19, 2007, pursuant to OSAH Rule 15, Intervenor filed a motion for summary determination on Counts I, X, XI, and XV of the Petition. *See* GA. COMP. R. & REGS. r. 616-1-2-.15 (2007). On July 20, 2007, Respondent also filed a motion for summary determination on Counts I, X, XI, and XV of the Petition. Additionally, on July 20, 2007, Intervenor and Respondent filed separate motions for partial summary determination on Counts II, V, and VII of the Petition. On August 13, 2007, Petitioners filed a collective response to the motions for summary determination filed by Respondent and Intervenor.

A hearing on the motions for summary determination was held on August 17, 2007. After the hearing, this Tribunal issued an oral ruling granting the motions for summary determination as to Counts I, X, and XI. This Tribunal deferred ruling on the motions for summary determination as to Count XV and partial summary determination as to Counts II, V, and VII, to allow Petitioners to respond to EPD's introduction of a memorandum in support of its position and to clarify Petitioners' position with respect to Permit Condition 8.23.

On August 24, 2007, after consideration of the motions, the arguments presented, and Petitioners' supplemental response, this Tribunal issued an oral ruling granting the motions for summary determination on Count XV and partial summary determination on Counts II, V, VII. The bases of this Tribunal's rulings are set forth below.

[2] The Petition for Hearing was filed with the Director of EPD on June 13, 2007, and was received by the Office of State Administrative Hearings ("OSAH") on June 20, 2007.

Summary Determination Standard

On a motion for summary determination, the moving party must show by supporting affidavits or other probative evidence that there is no genuine issue of material fact for determination such that the moving party "is entitled to a judgment as a matter of law on the facts established." *Richie Pirkle, et al v. Envtl. Prot. Div., Dep't of Natural Res.*, OSAH-BNR-DS-0417001-58-Walker-Russell, 2004 Ga. ENV. LEXIS 73, at *6-7 (2004) (citing *Porter, et al v. Felker, et al*, 261 Ga. 421 (1991)); GA. COMP. R. & REGS. r. 616-1-2-.15(1). *See generally Piedmont Healthcare, Inc. v. Ga. Dep't of Human Res.*, 282 Ga. App. 302, 304-305 (2006) (observing that a summary determination is "similar to a summary judgment" and elaborating that an Administrative Law Judge "is not required to hold a hearing" on issues properly resolved by summary adjudication). Once a motion for summary determination is made and supported, the opposing party may not rest upon mere allegations or denials, but must show by supporting affidavit or other probative evidence that there is a genuine issue of material fact. *Guy Lockhart v. Dir., Envtl. Prot. Div., Dep't of Natural Res.*, OSAH-BNR-AE-0724829-33-RW, 2007 Ga. ENV LEXIS 15, at *3 (2007) (citing *Leonaitis v. State Farm Mutual Auto Ins. Co.*, 186 Ga. App. 854 (1988)); GA. COMP. R. & REGS. r. 616-1-2-.15(3).

Legal Background

Georgia law requires all air pollution sources to obtain permits from EPD before commencing construction and operation. *See* O.C.G.A. § 12-9-7(a). EPD administers its permitting program through rules and regulations adopted by the Georgia Board of Natural Resources. The rules governing air quality control are located in Chapter 391-3-1. *See generally* GA. COMP. R & REGS. r. 391-3-1-.01, *et seq.* These rules list specific requirements for various types of air permits depending on the air quality in the area of the source (i.e., whether the source is located in an area that is in "attainment" or "nonattainment" of applicable National Ambient Air Quality Standards ("NAAQS")), and on the potential air pollution emission rates from the source. *See generally* GA. COMP. R. & REGS. r. 391-3-1-.02 (providing specific emission limitations and standards). Early County, the site of the Longleaf's proposed coal-fired facility, lies in an "attainment area" for all regulated pollutants. This means that the air quality in the area is in compliance with state and federal air quality standards. *See* 40 C.F.R. § 81.311.

The federal Clean Air Act ("CAA"), 42 U.S.C. § 7401, *et seq.*, requires states to adopt regulatory programs for issuing a certain type of construction permit to major air pollution sources located in attainment areas. This permit is known as a "Prevention of Significant Deterioration" or "PSD" permit, because it is designed to prevent significant deterioration of air quality in areas that are currently meeting NAAQS. *See* 42 U.S.C. § 7470(1). Georgia has adopted a regulatory program for PSD permits, which the United States Environmental Protection Agency ("EPA") has approved as part of Georgia's State Implementation Plan ("SIP"). *See* 40 C.F.R. § 52.572. Therefore, in Georgia, the Director of EPD issues PSD permits to qualifying sources pursuant to Georgia's rules. *See* GA. COMP. R. & REGS. r. 391-3-1-.02(7) (providing rules for the prevention of significant deterioration of air quality).

PSD permits require a number of demonstrations and conditions to ensure protection of ambient air quality standards, or NAAQS, and to restrict future air quality degradation. *See* 42 U.S.C. § 7475(a)(3) (listing requirements for PSD permit applicants). All new major air pollution sources must utilize best available control technology ("BACT") for each pollutant regulated under EPA's New Source Review ("NSR") program. *See* 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(j)(2) ("A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.") (incorporated by reference in GA. COMP. R. & REGS r. 391-3-1-.02(7)(b)7). BACT is defined as follows:

> [A]n emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the Clean Air] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.

40 C.F.R. § 52.21(b)(12); GA. COMP. R. & REGS. r. 391-3-1-.02(7)(a)2 (incorporating 40 C.F.R. § 52.21(b) by reference).

Count I

In Count I of the Petition, Petitioners allege that the Permit is invalid because EPD failed to include a BACT emission limitation for carbon dioxide ("CO_2"). (Pet. at ¶ 37). In support of their claim, Petitioners rely on 40 C.F.R. §§ 52.21(j)(2) and (b)(50). (*Id.* at ¶ 34).

Section 52.21(j)(2) provides that "[a] new major stationary source shall apply best available control technology for each *regulated NSR pollutant* that it would have the potential to emit in significant amounts." 40 C.F.R. § 52.21(j)(2) (emphasis added); GA. COMP. R. & REGS. r. 391-3-1-.02(7)(b)7 (incorporating 40 C.F.R. § 52.21(j)(2) by reference). Thus, Section 52.21(j)(2) only requires BACT emission limitations for "regulated NSR pollutants." *See* 40 C.F.R. § 52.21(j)(2). Section 52.21(b)(50) defines "regulated NSR pollutant" as follows:

> Regulated NSR pollutant, for purposes of this section, means the following:
> (i) Any pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the Administrator (e.g., volatile organic compounds and NO[X] are precursors for ozone);
> (ii) Any pollutant that is subject to any standard promulgated under section 111 of the [CAA];

> (iii) Any Class I or II substance subject to a standard promulgated under or established by title VI of the [CAA]; or
> (iv) Any pollutant that otherwise is subject to regulation under the [CAA]; except that any or all hazardous air pollutants either listed in section 112 of the [CAA] or added to the list pursuant to section 112(b)(2) of the [CAA], which have not been delisted pursuant to section 112(b)(3) of the [CAA], are not regulated NSR pollutants unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the [CAA].

40 C.F.R. § 52.21(b)(50); GA. COMP. R. & REGS. r. 391-3-1-.02(7)(a)2 (incorporating 40 C.F.R. § 52.21(b) by reference).

Carbon dioxide does not fall into any of the Section 52.21(b)(50) categories. EPA has not promulgated a national ambient air quality standard ("NAAQS") for CO_2, has not listed CO_2 as a regulated pollutant in any section of the CAA, and has not established any other regulations for CO_2. *See generally Massachusetts v. EPA*, 127 S. Ct. 1438 (2007) (inherently recognizing that EPA has not, to date, regulated CO_2 emissions); *see, e.g., In re: Kawaihae Cogeneration Project, PSD/CSP Permit No. 0001-01-C*, 1997 EPA App. LEXIS 8, at *58 (1997) (upholding a permitting agency's conclusion that "there are no regulations or standards prohibiting, limiting or controlling the emissions of greenhouse gases from stationary sources . . . [c]arbon dioxide is not considered a regulated pollutant for permitting purposes."). Likewise, EPD has not promulgated any regulations restricting or limiting the emissions of CO_2.

Carbon dioxide is not a regulated NSR pollutant as defined by Section 52.21(b)(50). Accordingly, EPD was not required by Georgia Rule 391-3-1-.02(7)(b)7 to include a BACT emissions limitation for CO_2 in the Permit. As previously determined by this Tribunal on August 17, 2007, Respondent's and Intervenor's motions for summary determination as to Count I of the Petition are **granted**.

Counts II, V, and VII

In Counts II, V, and VII of the Petition, Petitioners allege, in part, that the Permit is invalid because EPD failed to consider all available production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for the control of sulfur dioxide, nitrogen oxides and particulate matter. Specifically, Petitioners assert that EPD failed to consider Integrated Gasification Combined Cycle (IGCC) technology among the pollution control technologies EPD considered in the agency's BACT analysis. (Pet. at ¶¶ 44-46, 58-60, 66-68 (alleging that IGCC technology should have been included in the BACT analysis for sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), and particulate matter ("PM")). In support of their claims, Petitioners rely on 40 C.F.R. § 52.21(b)(12) for the proposition that EPD did not properly consider all of the technologies and techniques available for control of SO_2, NO_x, and PM. (*Id.* at ¶¶ 44-45, 58-59, 66-67). Petitioners assert that IGCC is a production process, method, system, technique, fuel cleaning treatment or innovative fuel combustion technique that EPD was required to consider. *See* 40 C.F.R. § 52.21(b)(12); GA. COMP. R. & REGS. r. 391-3-1-.02(7)(a)2 (incorporating 40 C.F.R. § 52.21(b) by reference). EPD did not consider IGCC in its BACT analysis. (Longleaf Energy Associates, LLC's Motion for Partial Summary Determination as to Counts II, V and VII of the Petition ("Longleaf IGCC Mot.") at 8; EPD's Motion for Partial Summary Determination on Counts II, V, and VII of the Petition for Hearing ("EPD IGCC Mot.") at 4).

BACT is defined as a limitation on emissions of regulated pollutants "from any *proposed* major stationary *source*" that "is achievable for *such source*...through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant." 40 C.F.R. § 52.21 (b)(12) (emphasis added). Thus, EPD's BACT analysis is a source-specific inquiry.

The Environmental Appeals Board describes this source-specific BACT analysis as follows:

> [P]ermit conditions are imposed for the purpose of ensuring that the proposed source . . . uses emission control systems that represent BACT . . . . These control systems, as stated in the definition of BACT, may require application of "production processes and available methods, systems, and techniques . . ." to control the emissions . . . . *The permit conditions that define these systems are imposed on the source as the applicant has defined it . . . .*

In the Matter of Pennsauken County, New Jersey Resource Recovery Facility, PSD Appeal No. 88-8, 2 E.A.D. 667, 1988 EPA App. LEXIS 27, at *13 (1988) (citation omitted) (emphasis added).

In its PSD permit application, Longleaf listed its proposed source as a "pulverized coal-fired electric power generation facility" that would include two pulverized coal-fired boilers and two steam turbine generators. *See* Prevention of Significant Deterioration Permit Application for the Longleaf Energy Station, Early County, Georgia, at 1-1, 1-3 (November 19, 2004) (Longleaf IGCC Mot., Ex. D).[3] Accordingly, in its BACT analysis, EPD included those processes, methods, systems and techniques that could be applied to facilities consisting of pulverized coal-fired boilers and steam generators. *See* 40 C.F.R. § 52.21(b)(12). The resulting Permit requires Longleaf to implement innovative fuel combustion techniques (low NO_x burners and over-fire air) as well as pollution control systems (selective catalytic reduction, fabric filter baghouses, and a dry scrubber) that have been and can be used on pulverized coal-fired electric generating facilities. *See* Permit at 2 (Pet., Ex. A).

[3] *Available at* http://www.georgiaair.org/airpermit/psd/dockets/longleaf/facilitydocs/Longleaf_PSD_Applic.pdf (last visited November 20, 2007).

Because BACT is a source-specific inquiry, analysis of alternative processes that, if applied, would redefine the air pollution source that a PSD Permit applicant has proposed is not required. EPA's guidance to permitting authorities regarding BACT analysis, the New Source Review Workshop Manual (Draft) ("Draft NSR Manual"), explains this limitation on the scope of BACT analyses as follows:

> Historically, *EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives.* For example, applicants proposing to construct a coal-fired electric generator have not been required by EPA as part of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity). However, this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire. Thus, a gas turbine normally would not be included in the list of control alternatives for a coal-fired boiler.

ENVIRONMENTAL PROTECTION AGENCY, NEW SOURCE REVIEW WORKSHOP MANUAL, B.13 (Draft, 1990) (emphasis added) (Longleaf IGCC Mot., Ex. E).

Consistent with EPA's approach in the Draft NSR Manual, the Environmental Appeals Board has repeatedly held that a BACT analysis does not require consideration of production processes that would redefine the proposed source. *See In re Kendall New Century Development*, PSD Appeal No. 03-01, 11 E.A.D. 40, 50-52 (2003) (upholding a permitting authority's decision to exclude from its BACT analysis those other production processes that would change the size and design of the proposed source) (Longleaf IGCC Mot., Ex. F); *In the Matter of Hawaiian Commercial and Sugar Company Permit No. HI 89-01*, PSD Appeal No. 92-1,4 E.A.D. 95, 99, 1992 EPA App. LEXIS 42, at *12-14 (1992) (relying on passage from the Draft NSR Manual to conclude that the state of Hawaii was not required to consider a combined-cycle power plant as an alternative to the proposed circulating fluidized bed coal plant because that alternative would redefine the proposed source); *In the Matter of: Old Dominion Electric*

Cooperative Permit Applicant, PSD Appeal No. 91-39, 3 E.A.D. 779, 1992 EPA App. LEXIS 37, at *30-32, 32 n.38 (1992) (holding that a state PSD permitting authority was not required to consider natural gas as an alternative fuel for a proposed coal-fired facility because the state believed the use of natural gas would redefine the proposed source – noting that "[t]raditionally, EPA does not require a PSD applicant to change the fundamental scope of its project…."); *In the Matter of Pennsauken County*, 1988 EPA App. LEXIS 27, at *13-14 ("Although imposition of [BACT] conditions may, among other things, have a profound effect on the viability of the proposed facility as conceived by the applicant, the [BACT] conditions themselves *are not intended to redefine the source*.") (emphasis added).

Thus, the Clean Air Act regulations, EPA guidance and federal administrative decisions all demonstrate that EPD was not required to consider as part of its BACT analysis those processes, methods, systems or techniques that, if applied, would have resulted in the redefinition of the pulverized coal-fired steam electric generating facility that Longleaf proposed in its PSD permit application.

IGCC power plants and pulverized coal-fired power plants are distinct and separate types of power generation facilities. (Aff. of Kennard F. Kosky ("Kosky Aff.") at ¶ 4 (Longleaf IGCC Mot., Ex. A); Aff. of James Capp ("Capp Aff.") at ¶ 6 (EPD IGCC Mot., Ex. A)). The major difference between the two types of facilities is that they combust *different fuels* in *different combustion devices* to produce electricity. (Kosky Aff. at ¶¶ 5, 7; Capp Aff. at ¶¶ 6-7). A pulverized coal-fired steam electric generating facility burns *pulverized coal* in a *boiler* to produce steam that turns a turbine that generates electricity. (Kosky Aff. at ¶ 5; Capp Aff. at ¶ 6). In contrast, an IGCC facility burns *synthetic gas* in a jet engine, called a *combustion turbine*, that produces electricity. (Kosky Aff. at ¶ 7; Capp. Aff. at ¶ 6).

From an engineering design perspective, a pulverized coal-fired power plant utilizes a single process: finely crushed coal is burned in a boiler to produce steam, and the steam turns a turbine to generate electricity. (Kosky Aff. at ¶ 5). By comparison, IGCC is a series of chemical processes in which coal or another fuel is fed into a chemical plant to manufacture a synthetic gas. *Id.* at ¶ 7. The synthetic gas is then burned in a large stationary combustion turbine, which produces electricity. *Id.* Therefore, unlike a pulverized coal-fired power plant, which from an engineering perspective is a single process, the IGCC design has two distinct components: a chemical plant which produces the gas; and a separate power plant which burns the gas to produce electricity. *Id.* at ¶ 8.

These basic engineering differences are reflected by the significant additional machinery required by an IGCC facility. (Capp Aff. at Ex. 3 & Ex. 4 (schematics showing the mechanical components of a coal-fired power plant and an IGCC, respectively)). An IGCC facility uses a gasifier unit. (Capp Aff. at ¶ 7 & Ex. 4). Oxygen is supplied by an air separation unit ("ASU"), which separates the nitrogen from oxygen in the air. *Id.* The gasifier chemically converts the coal from (mostly) carbon, along with oxygen and steam, under very high pressure, to form carbon monoxide and hydrogen (and contaminants). *Id.* This gas ("syngas") is then cooled and cleaned in order to prevent damage to the combustion turbine blades when the gas is burned. (Capp Aff. at ¶ 10 & Ex. 4).

In summary, operation of an IGCC power plant requires the following components: a gasifier, ASU, syngas cooling equipment, syngas cleaning equipment, and a combustion turbine. (Capp Aff. at ¶¶ 7,10 & Ex. 4). A pulverized coal-fired power plant does not utilize any of these major mechanical components. (Capp Aff. at ¶¶ 7, 10; *see id.* at Ex. 3).

Finally, in an IGCC facility, the gasifier produces a coal minerals slag and the syngas cleaning produces a sulfur byproduct – both of which must be handled and processed. (Capp Aff. at ¶¶ 8-9). A pulverized coal-fired power plant has no such issues – all of the material collected by the air pollution control devices at a pulverized coal-fired power plant may be safely disposed in an on-site landfill. *Id.*

As is apparent from the physical and operational differences between IGCC power plants and pulverized coal-fired steam electric generating facilities, IGCC is not a process, method, system or technique that can be applied to a pulverized coal-fired steam electric generating facility without redefining the proposed air pollution source. For these reasons, EPD decided not to consider IGCC in its BACT analysis:

> IGCC is a physically and chemically distinct method of producing electricity that cannot be compared to the [pulverized coal] fired boiler proposed at Longleaf without redefining the source. Neither federal law nor Georgia law required the consideration of technologies that would redefine the proposed source.

Final Determination, SIP Permit Application No. 15846, at 33 (May 2007) (Longleaf IGCC Mot., Ex. B).[4]

EPD's conclusion that the application of IGCC technology to Longleaf's pulverized coal-fired steam electric generating facility would result in a redefinition of the proposed air pollution source is consistent with decisions from other states. See *Blue Skies Alliance, et al v. Texas Commission on Environmental Quality*, Cause No. D-1-GN-06-002911 (2007) (affirming the Texas Commission on Environmental Quality's ("TCEQ") decision to issue a permit for a

[4] *Available at* http://www.georgiaair.org/airpermit/psd/dockets/longleaf/permitdocs/0990030fd.pdf (last visited November 20, 2007).

pulverized coal-fired steam electric generating facility, including TCEQ's Interim Order[5] that a PSD permit applicant for a pulverized coal-fired steam electric generating facility is not required to include IGCC technology in its BACT analysis) (Longleaf IGCC Mot., Ex. I); *Sierra Club, et al v. Environmental and Public Protection Cabinet*, File No. DAQ-26003-037 and DAQ-26048-037, 30 (2006) (Longleaf IGCC Mot., Ex. K) (upholding the issuance of a PSD permit to construct a pulverized coal-fired steam electric generating facility despite the fact that the state's permitting authority had not required the applicant to include IGCC technology in its BACT analysis); *In the Matter of Linda Chipperfield, et al. v. Missouri Dept. of Natural Resources, et al.*, Appeal No. 05-139PA, 13-14 (2005) (Order Ruling on Motions to Dismiss) (Longleaf IGCC Mot., Ex. L) (dismissing a claim that the State had failed to properly evaluate alternative combustion systems, including IGCC, in its BACT analysis for a proposed pulverized coal-fired boiler and finding that Petitioners sought to redefine the source).

EPA guidance indicates that states may, as a matter of *discretion*, choose to consider IGCC in the BACT analysis for a pulverized coal-fired boiler facility. *See* ENVIRONMENTAL PROTECTION AGENCY, NEW SOURCE REVIEW WORKSHOP MANUAL, B.13 (1990) (Longleaf IGCC Mot., Ex. E) (emphasis added). As a result, some states have exercised their discretion to consider IGCC as part of their BACT analyses for pulverized coal-fired steam electric generating facilities. *See, e.g., In re: Prairie State Generating Co., PSD Permit No. 189808AAB*, PSD Appeal No. 05-05, Slip Opinion, 35-36 (2006) (noting that while the state permitting authority had required IGCC to be included in the BACT analysis for the proposed pulverized coal-fired

[5] A certified question of law had been previously presented in that case as to whether an applicant that proposes to construct a pulverized coal boiler power plant is required to include other electric generation technologies, such as IGCC, in its BACT analysis. *See Interim Order Re: Application of Sandy Creek Associates L.P. for Air Quality Flexible Permit No. 70861 and PSD Permit No. PSD-TX-1039*, TCEQ Docket No. 2005-0781-AIR, SOAH Docket No, 582-05-5612 (Dec. 29, 2005) (Longleaf IGCC Mot., Ex. J).

boiler facility, IGCC was ultimately not selected as BACT for the facility) (Longleaf IGCC Mot., Ex. O). However, there is no authority for Petitioners' contention in Counts II, V and VII that EPD was legally *required* to include IGCC technology in its BACT analysis for Longleaf's proposed pulverized coal-fired steam electric generating facility.

IGCC is not a process, method, system or technique that can be applied to a pulverized coal-fired boiler facility without redefining the proposed air pollution source. Accordingly, because BACT is a source-specific inquiry, EPD was not *required* to consider IGCC in the BACT analysis for the Longleaf facility. As previously determined by this Tribunal on August 17, 2007, Respondent's and Intervenor's motions for partial summary determination as to the IGCC issue contained in Counts II, V, and VII of the Petition are **granted**.

Count X

In Count X, Petitioners allege that the Permit is invalid because it does not contain a BACT emission limitation in the form of a "visible emission standard" as that term is used in 40 C.F.R. § 52.21(b)(12). (Pet. at ¶¶ 81-83). *See* 40 C.F.R. § 52.21(b)(12) (defining BACT as "an emissions limitation *(including a visible emission standard)* based on the maximum degree of reduction for each pollutant subject to regulation . . .") (emphasis added); GA. COMP. R. & REGS. r. 391-3-1-.02(7)(a)2 (incorporating 40 C.F.R. § 52.21(b) by reference).

"Opacity" refers to a visible emission standard that gauges the visibility of emissions exiting a stack. *See Sierra Club v. Ga. Power Co.*, 443 F.3d 1346, 1350 n.4 (11th Cir. 2006); GA. COMP. R. & REGS. r. 391-3-1-.01(ss) (defining "opacity" as "the degree to which emissions reduce the transmission of light and obscure the view of an object in the background, and is expressed in terms of percent opacity"). Section 52.21(j)(2) provides that "[a] new major stationary source shall apply best available control technology for each *regulated NSR pollutant* that it would have the potential to emit in significant amounts." 40 C.F.R. § 52.21(j)(2) (emphasis added); GA. COMP. R. & REGS. r. 391-3-1-.02(7)(b)7 (incorporating 40 C.F.R. § 52.21(j)(2) by reference). Thus, as discussed *supra*, Section 52.21(j)(2) only requires BACT emission limitations for "regulated NSR pollutants." *See* 40 C.F.R. § 52.21(j)(2). In this case, the Permit contains numerical emission limits for each regulated NSR pollutant that will be emitted in significant amounts. *See* Air Quality Permit No. 4911-099-0030-P-01-0, Conditions 2.15 & 2.16 (May 14, 2007) (Pet., Ex. A).

Opacity is not a regulated NSR pollutant. *See Sierra Club*, 443 F.3d at 1350 n.4 ("While *opacity is not itself a regulated pollutant*, it acts as a measurement surrogate for particulate matter (PM), which is a regulated pollutant . . . .") (emphasis added). Thus, to the extent that Petitioners claim that EPD should have conducted a BACT analysis for opacity itself, this Tribunal finds that EPD was not required by Georgia Rule 391-3-1-.02(7)(b)7 to include a BACT emissions limitation for opacity in the Permit.

Here, the Permit requires Longleaf to monitor PM emissions through the use of a continuous emissions monitoring system ("CEMS"). *See* Air Quality Permit No. 4911-099-0030-P-01-0, Conditions 4.1(t) & 5.2(f) (May 14, 2007) (Pet., Ex. A). Rather than rely on an observer's periodic opacity measurements to monitor the facility's PM emissions, Longleaf will monitor its PM emissions on a more precise and continuous basis through use of its CEMS, day and night and without regard to the weather. The EPA has stated that under the new NSPS regulations for electric utility steam generating units, opacity monitoring is not required for sources in these instances:

> Since opacity is used as an indication on PM emissions, EPA has provided sources with two options to demonstrate continuous compliance with the amended PM standard. Sources may elect to install and operate PM CEMS

> and demonstrate compliance each boiler operating day. For these units, *opacity monitoring shall no longer be required.*

71 Fed. Reg. 9866, 9872 (2006) (emphasis added).

Moreover, there is no requirement that the Permit contain a "visible emission standard" in addition to a numerical emission limitation for each pollutant that is subject to a BACT analysis. The phrase "including a visible emission standard" appears in parentheses in the definition of BACT. *See* 40 C.F.R. § 52.21(b)(12); GA. COMP. R. & REGS. r. 391-3-1-.02(7)(a)2 (incorporating 40 C.F.R. § 52.21(b) by reference). "[T]he meaning of [] words within [] parentheses should be considered as incidental explanatory matter which is not a part of, or at least is not essential to, the main statement." *Chipperfield et al. v. Mo. Air Conservation Comm'n*, 229 S.W.3d 226, 252 (Mo. Ct. App. 2007).

In *Chipperfield*, the court examined a Missouri regulation defining BACT as "[a]n emission limitation (*including a visible emission limit*) . . . ." *Id.* at 251. The court relied on the use of parentheses in the regulation to conclude that the regulatory definition of BACT did not require the use of a "visible emission limit." *Id.* at 251-52 ("Appellants' argument that the parenthetical phrase adds a condition to the regulation that every emission limitation must include a visible emission limit, is inconsistent with the purpose of a parenthetical phrase to provide non-essential information."). This Tribunal finds the *Chipperfield* court's reasoning persuasive.

The parenthetical mention of a "visible emission standard" in 40 C.F.R. § 52.21(b)(12) does not require that each BACT emission limitation must *also* be in the form of a visible emission standard. To hold otherwise "would lead to the absurd result of requiring a visible emission limit for an invisible pollutant" such as carbon monoxide. *See Chipperfield*, 229 S.W.3d at 252.

This Tribunal finds that the parenthetical reference to a "visible emission standard" provides an alternative means of expressing the emission limitation. In other words, a permit is not required to have both a numerical emission limit *and* a visible emission standard. Rather, the permit is required to have "an emission limitation." That limitation may be a numerical limit or, for certain pollutants, it may be expressed in the form of a visible emission standard.

For these reasons, as previously determined by this Tribunal on August 17, 2007, Respondent's and Intervenor's motions for summary determination as to Count X of the Petition are **granted.**[6]

Count XI

In Count XI, Petitioners allege that the Permit is invalid because Longleaf did not submit an adequate modeling demonstration for $PM_{2.5}$.[7] In support of their claim, Petitioners rely on 40 C.F.R. § 52.21(k) and Georgia Rule 391-3-1-.02(7)(b)8, both of which require an applicant to demonstrate that air pollution from a proposed facility will not violate any NAAQS or "any applicable maximum allowable increase over the baseline concentration in any area." (Pet. at ¶ 86). *See* 40 C.F.R. § 52.21(k); GA. COMP. R. & REGS. r. 391-3-1-.02(7)(b)8 (incorporating 40 C.F.R. § 52.21(k) by reference).

Section 52.21(k) provides:

> Source impact analysis. The owner or operator of the proposed source or modification shall demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), would not cause or contribute to air pollution in violation of:
> (1) *Any national ambient air quality standard* in any air quality control region; or
> (2) Any applicable maximum allowable increase over the baseline concentration in any area.

[6] Petitioners did not oppose the Motion for Summary determination as to Count X. (Pet'r Collective Response to the Motions for Summary Determination at 1 n.1).

[7] (Pet. at ¶ 88). "$PM_{2.5}$" refers to particulate matter with a diameter of 2.5 microns or less. 40 C.F.R. § 50.7.

40 C.F.R. § 52.21(k) (emphasis added).

The Environmental Protection Agency ("EPA") has promulgated a national ambient air quality standard for $PM_{2.5}$. *See National Ambient Air Quality Standard for Particulate Matter*, 62 Fed. Reg. 38652, 38711 (1997) (codified at 40 C.F.R. § 50.7). Intervenor did not conduct $PM_{2.5}$ specific modeling for its proposed coal-fired power plant. (Longleaf Energy Associates, LLC's Motion for Summary Determination on Counts I, X, XI, XV of the Petition ("Longleaf Summ. Determ. Mot.") at 8).

Although the EPA did promulgate a NAAQS for $PM_{2.5}$, due to technical uncertainties associated with modeling and monitoring $PM_{2.5}$, EPA has not yet promulgated regulations governing the implementation of this new $PM_{2.5}$ NAAQS for facilities, like Longleaf, that are subject to New Source Review ("NSR"). *See* Memorandum from John S. Seitz, Director, EPA Office of Air Quality Planning & Standards, Interim Implementation of New Source Review Requirements for $PM_{2.5}$, at 1 (Oct. 23, 1997) ("Seitz Memorandum") (Longleaf Summ. Determ. Mot., Ex. G). No $PM_{2.5}$-specific modeling protocols have been established by EPA. *Id.* at 2. Rather, EPA has stated that states may use PM_{10} as a surrogate for $PM_{2.5}$ to determine compliance with PSD permitting requirements. *Id.*

Longleaf submitted its PSD permit application to EPD in November 2004. *See* Prevention of Significant Deterioration Permit Application for the Longleaf Energy Station, Early County, Georgia (November 19, 2004).[8] At that time, there were no rules or regulations governing how PSD permitting authorities or applicants were to comply with $PM_{2.5}$ requirements. The only official guidance was the 1997 Seitz Memorandum. That memorandum stated that it was "administratively impractical . . . to require sources and State permitting

[8] *Available at* http://www.georgiaair.org/airpermit/psd/dockets/longleaf/facilitydocs/Longleaf_PSD_Applic.pdf (last visited November 20, 2007).

authorities to attempt to implement PSD permitting for $PM_{2.5}$" due to the "significant technical difficulties" that existed regarding "$PM_{2.5}$ monitoring, emissions estimation, and modeling." (Seitz Memorandum at 1, 2). As a result, EPA recommended "that sources should continue to meet PSD and NSR program requirements for controlling PM_{10} emissions . . . and for analyzing impact on PM_{10} air quality. Meeting these measures in the interim will serve as a surrogate approach for reducing $PM_{2.5}$ emissions and protecting air quality." *Id.* at 2. Therefore, as of November 2004, EPA endorsed a policy whereby a PSD permit applicant could satisfy PSD permitting requirements for $PM_{2.5}$ by relying on the results of its PM_{10} air quality modeling.

On December 17, 2004, EPA took its first step towards implementing the $PM_{2.5}$ NAAQS by designating non attainment areas for $PM_{2.5}$. *See* Air Quality Designations and Classifications for the Fine Particles ($PM_{2.5}$) National Ambient Air Quality Standards, 70 Fed. Reg. 944 (2005) (codified at 40 C.F.R. Part 81) (Longleaf Summ. Determ. Mot., Ex. H). However, shortly after the $PM_{2.5}$ nonattainment areas were designated, EPA again issued guidance advising states to continue using PM_{10} as a surrogate for determining compliance with the $PM_{2.5}$ NAAQS. *See* Memorandum from Stephen D. Page, Director, Implementation of New Source Review Requirements in $PM_{2.5}$ Nonattainment Areas (April 5, 2005) ("Page Memorandum") (Longleaf Summ. Determ. Mot., Ex. I). Specifically, EPA stated that "[b]ecause we have not promulgated the $PM_{2.5}$ implementation rule, administration of a $PM_{2.5}$ PSD program remains impractical. Accordingly, *States should continue to follow the October 23, 1997, guidance for PSD requirements*." *Id.* at 4 (emphasis added).

EPA has recently issued an implementation rule for $PM_{2.5}$, Clean Air Fine Particle Implementation Rule, 72 Fed. Reg. 20586 (Apr. 25, 2007) (to be codified at 40 C.F.R. Part 51). However, this new implementation rule does not include requirements for facilities, like

Longleaf, that are subject to NSR. *Id.* at 20586. As the preamble accompanying the new rule provides, "this rule does not include final $PM_{2.5}$ requirements for the (NSR) program; the final NSR rule will be issued at a later date." *Id.* Thus, as of the date of issuance of the Permit, there were no relevant rules applicable to new sources, like Longleaf, that required implementation of $PM_{2.5}$ modeling.

With no available federal or state regulations regarding the implementation of $PM_{2.5}$ NAAQS, Intervenor and EPD relied on "EPA's guidance to use PM_{10} as a surrogate for $PM_{2.5}$" to conclude that emissions from the coal-fired facility will not cause or contribute to air pollution levels of $PM_{2.5}$ in violation of state and federal law. *See* Final Determination, SIP Permit Application No. 15846, at 8 (May 2007) (responding to EPA's comment suggesting that EPD expressly state that it is following EPA's guidance to use PM_{10} as a surrogate for $PM_{2.5}$) (Longleaf Summ. Determ. Mot., Ex. C).

Intervenor's chosen approach was entirely consistent with the only official guidance that EPA had published regarding $PM_{2.5}$. Moreover, EPA's comments on the draft permit, which were incorporated into the Final Determination, confirmed that using PM_{10} as a surrogate for $PM_{2.5}$ was still an accepted practice.[9] Accordingly, there was no requirement that Intervenor perform and submit air modeling for $PM_{2.5}$. As previously determined by this Tribunal on

[9] *See* Final Determination, SIP Permit Application No. 15846, at 8 (May 2007) (Longleaf Summ. Determ. Mot., Ex. C). The Comment and Response in the Final Determination regarding PM_{10} and $PM_{2.5}$ were as follows:

> 10. <u>Fine Particles</u>
>
> $PM_{2.5}$ is a regulated NSR pollutant and should be acknowledged as such in the final determination. At your discretion, you could state that *you are following EPA's guidance to use PM_{10} as a surrogate for $PM_{2.5}$* until final $PM_{2.5}$ NSR implementation rules are adopted.
>
> Response: EPD is following EPA's guidance to use PM_{10} as a surrogate for $PM_{2.5}$ until final $PM_{2.5}$ NSR implementation rules are adopted.

Id. (emphasis added).

August 17, 2007, Respondent and Intervenor's motion for summary determination as to Count XI of the Petition is **granted.**

Count XV

In Count XV, Petitioners allege that the Permit is invalid because Condition 8.23 of the Permit creates an exemption for excess emissions which might occur during periods of startup and shutdown at Longleaf's facility. (Pet. at ¶ 110). *See* Permit at 24-25 (Pet., Ex. A). In support of their claim, Petitioners rely on 42 U.S.C. § 7602(k) and Georgia Rule 391-3-1-.01(v), both of which require emission limitations to control air pollution on a continuous basis. (Pet. at ¶ 110). *See* 42 U.S.C. § 7602(k); GA. COMP. R. & REGS. r. 391-3-1-.01(v).

Condition 8.23 of the Permit provides as follows:

> a. Excess emissions resulting from startup, shutdown, malfunction of any source which occur though ordinary diligence is employed shall be allowed provided that:
>
> i. The best operational practices to minimize emissions are adhered to;
>
> ii. All associated air pollution control equipment is operated in a manner consistent with good air pollution control practice for minimizing emissions; and
>
> iii. The duration of excess emissions is minimized.
>
> b. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction are prohibited and are violations of this Permit.
>
> c. The provisions of this condition and Georgia Rule 391-3-1-.02(2)(a)(7) shall apply only to those sources which are not subject to any requirement under Georgia Rule 391-3-1-.02(8) -- New Source Performance Standards or any requirement of 40 C.F.R. Part 60, as amended, concerning New Source Performance Standards.

Permit at 24-25 (Pet., Ex. A).

Section 7602(k) defines "emission limitation" and "emission standard" in the CAA as "a requirement established by the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants *on a continuous basis.*" 42 U.S.C. § 7602(k) (emphasis added). Georgia Rule 391-3-1-.01(v) defines "emission limitation" and "emission standard" in Georgia's State Implementation Plan ("SIP") for the CAA as "a requirement established which limits the quantity, rate, or concentration of emissions of air contaminants *on a continuous basis*." GA. COMP. R. & REGS. r. 391-3-1-.01(v) (emphasis added).

However, Georgia Rule 391-3-1-.02(2)(a)7 (the "SSM Rule") provides an exemption for excess emissions which might occur during periods of startup, shutdown, and unavoidable malfunction. *See* GA. COMP. R. & REGS. r. 391-3-1-.02(2)(a)7. Georgia's SSM Rule has been approved by the Environmental Protection Agency ("EPA"), and that approval remains effective. *See Sierra Club v. Ga. Power Co.*, 443 F.3d 1346, 1351 (11th Cir. 2006) (noting that Georgia's SSM Rule was approved by the EPA in 1980); 40 C.F.R. § 52.572 (renewing the approval). Moreover, "[t]he SSM rule is categorical and unambiguous" regarding the exemption it provides during startup and shutdown. *Sierra Club*, 443 F.3d at 1353.

In *Sierra Club v. Ga. Power*, the Eleventh Circuit construed a challenge to a permit condition that contained language almost identical to the SSM Rule as a challenge to the SSM Rule itself. *Sierra Club*, 443 F.3d at 1357. The Court rejected the facial challenge, stating that the SSM Rule "remains the law" and therefore the corresponding permit condition "must be read accordingly." *Id.*

The language used in Condition 8.23 of the Permit is virtually identical to the SSM Rule.[10] Accordingly, the Permit's conditional allowance in Condition 8.23 for excess emissions is entirely consistent with federal and Georgia law. As previously determined by this Tribunal

[10] Condition 8.23 differs from Rule 391-3-1-.02(2)(a)(7) in only one minor detail. *Compare* Condition 8.23(c) (using the language "[t]he provisions of this *condition and Georgia Rule 391-3-1-.02(2)(a)(7)), with* Ga. Comp. R. & Regs. r. 391-3-1-.02(2)(a)(7)(iii) (using the language "[t]he provisions of this *paragraph 7*") (emphasis added).

on August 17, 2007, Respondent and Intervenor's motion for summary determination as to Count XV of the Petition is **granted**.

ORDER

For the foregoing reasons, Counts I, X, XI, and XV are dismissed in their entirety. Additionally, the claims related to IGCC in Counts II, V, and VII are dismissed.

SO ORDERED December 18 **, 2007**

Stephanie M. Howells

STEPHANIE M. HOWELLS
Administrative Law Judge

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RECEIVED 1/29/08

BEFORE THE BOARD OF ENVIRONMENTAL REVIEW OF THE STATE OF MONTANA

IN THE MATTER OF: THE APPEAL BY SOUTHERN MONTANA ELECTRIC REGARDING ITS AIR QUALITY PERMIT NO. 3423-00 FOR THE HIGHWOOD GENERATION STATION	**CASE NO. BER 2007-06 AQ**

THIRD ORDER SETTING HEARING AND DENYING MOTION TO STRIKE PORTIONS OF AFFIDAVIT OF APPELLANTS

On December 21, 2007, the Board of Environmental Review (Board) heard oral argument on the following motions:

1. Motion of Southern Montana Electrical Generation & Transmission Cooperative, Inc. (SME) for Summary Judgment dated November 19, 2007.
2. Motion of Montana Environmental Information Center (MEIC) and Citizens for a Clean Earth (CCE) for Summary Judgment dated November 16, 2007.
3. Motion of the Department of Environmental Quality (Department) for Summary Judgment dated December 12, 2007.

On January 11, 2008, the Board heard supplemental argument on the portions of the summary judgment motions pertaining to whether the Department complied with federal and state requirements in not deeming CO2 as a regulated pollutant subject to regulation includable in a Best Available Control Technology (BACT) analysis in issuing Permit No. 3423-00 to SME. The Board decided on January 11, 2008 that CO2 is not a regulated pollutant, "subject to regulation" and BACT requirements. The Board will review and adopt a written order concerning this decision subsequent to, or as an adjunct to the hearing on January 22 and 23, 2008.

On December 21, 2007, the Board decided to deny the portions of the Motions for Summary Judgment referenced above that address whether the Department correctly applied the law concerning PM 2.5 emissions when it issued Permit No. 3423-00 to SME on May 11, 2007. A hearing concerning issues subsumed within this question is set for January 22, 2008, at 10 a.m. through January 23, 2008.

On November 19, 2007, SME filed a "Motion to Strike Portions of the Affidavit of Appellants Montana Environmental Information Center & Citizens for Clean Energy" ("Motion") together with a "Memorandum in Support of Motion to Strike Portions of the Affidavit of Appellants [MEIC] and [CCE]." Response and reply briefs were filed respectively by the Appellants on December 4, 2007, and by SME on December 11, 2007. Upon a review of the Motion and briefs of the parties, the Motion is denied.

The contested statements in the Affidavit filed June 8, 2007, by Ms. Anne Hedges pertaining to (1) the use of "severe environmental impacts,"; (2) the requirement that the Department conduct a top-down analysis for BACT for CO2; and (3) the statement that there was not one reference to PM 2.5 in the permit that was issued are primarily background, somewhat argumentative statements which were clarified in the discovery stages or in the Affidavit itself. The Affidavit is not a "pleading" per se conducive to a motion to strike but is intended to serve as a background and basis for contesting the Department permitting decision on both factual and legal bases. In affidavit form, especially where, as here, the Affidavit was signed by a non-attorney, it is difficult to reconcile the fundamental requirement of an affidavit which is to set forth facts under oath, Mont. Code Ann. § 26-1-1001 and the impetus for the party appealing the permit to list legal arguments contesting the permitting action. See Mont. Code Ann. § 75-2-211(10). The contested statements, referenced in the Motion, are statements of both fact and law. The accuracy and correctness of the contested statements in the Affidavit are best developed through a disposition on the merits which the parties were commencing even before the Motion was filed through discovery. The second contested statement concerning CO2 is now moot given the decision of the Board on January 11, 2008. The first and second statements still may be considered as a part of the Affidavit.

DATED this 22nd day of January, 2008.

for Thomas M. Schneider

KATHERINE J. ORR
Hearing Examiner
Agency Legal Services Bureau
1712 Ninth Avenue
P.O. Box 201440
Helena, MT 59620-1440

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Federal Energy Regulatory Commission
February 15, 2008
States of US Competitive Wholesale Power Markets
CERAWEEK 2008 - Quest for Security:
Strategies for a New Energy Future
Statement of
Chairman Joseph T. Kelliher

"I want to thank you for inviting me to speak today. I appreciate the opportunity to discuss U.S. wholesale power market competition policy.

Before I begin, let me offer the usual disclaimer. The views I am about to express do not necessarily represent the views of the Federal Energy Regulatory Commission (FERC), my colleagues on the Commission, or the FERC staff. I speak only for myself.

In my view, U.S. competitive wholesale power markets are working well, and wholesale competition policy has been a success. This is true notwithstanding the pressure from higher fuel prices, principally coal and natural gas, which put upward pressure on wholesale power prices.

I want to be clear that U.S. wholesale power policy is not "deregulation". To me, "deregulation" suggests the absence of regulation. Since we are here in Texas, I will say that "deregulation" brings to mind images of a Clint Eastwood Western movie, with gunfighters shooting it out in the street in a town that has no sheriff and no laws. There is a sheriff in wholesale power markets, and there are rules that govern U.S. wholesale power markets.

The United States relies on a mixture of competition and regulation to govern wholesale power markets. Our goal is perfect competition, textbook competition, competition that is so beautiful it would make an economist weep.

I accept that we may not achieve that goal, and that perfect competition may not exist outside the textbook. In our pursuit of perfect competition we may fall short. But if so we will at least have achieved more perfect competition.

What is the proper measure of success for U.S. wholesale power competition policy? Not movements in retail prices, which are driven largely by movements in fuel prices. The truest measure of success would be a counterfactual – what would power prices be absent the adoption of competition policy 25 years ago? But that could never be demonstrated to complete satisfaction.

In my view, the proper measure of success is whether wholesale power markets have the characteristics of perfect or textbook competition. Wholesale markets currently reflect most of these characteristics, but not all, and there is room for improvement.

One reason it is clear that U.S. wholesale policy is not now and has never been deregulation is that FERC never stopped regulating wholesale power markets. FERC's regulatory role has certainly changed over time. Twenty-five years ago FERC wholesale power regulation largely constituted setting a host of wholesale power sales rates for individual sellers through traditional cost of service rate regulation. Now FERC approves market rules, prevents market power exercise through our market based rate test and ratemaking authority, polices market manipulation, and enforces its rules through exercise of its civil penalty authority. I would submit the current FERC regulatory role is different, but not smaller, than it was 25 years ago.

Higher fuel prices are leading some to question wholesale competition policy, and we hear the siren song of reregulation. But it is not entirely clear what the advocates of reregulation are proposing, and to some extent their position is inchoate. But the logic of their position suggests total reliance on regulation and the total absence of competition. It wishes away the independent power producers that have added most U.S. electricity supply over the past 25 years. It presumes that interstate commerce in power disappears, that utilities become walled cities, and that the U.S. relies on pure vertical integration.

In my view, such a scenario is clearly impossible. We cannot put the competition genie back into the bottle, even if there was a will to do so. But if this impossible scenario were actually realized it would produce terrible outcomes for consumers. It would also vastly complicate U.S. efforts to meet the security of electricity supply challenge and make it nearly impossible to meet the climate change challenge.

It is important to appreciate that U.S. wholesale competition policy was not inadvertent. It was a deliberate choice reflected in three major federal laws enacted over the past 30 years. The U.S. consciously embraced competition policy after the comprehensive failure of traditional regulation to assure security of supply at reasonable cost.

Calls for reregulation are essentially a cry for lower electricity prices. But there is little that reregulation can do to change the underlying fuel costs that are the principal driver on power prices. Traditional rate regulation cannot readily change the price of natural gas and coal.

FERC is not complacent about the state of wholesale power markets. We seek steady reform to strengthen wholesale competition, encourage generation entry, improve market access and grid access, establish good market rules, prevent market power exercise and market manipulation, assure effective enforcement, improve market transparency, provide contract certainty, reinforce the power grid, and improve demand response.

We have pursued a series of reforms over the past two years, most of which were initiated by the Commission itself. We are currently in the midst of a competition proceeding that began a year ago. This effort is not our first step in promoting effective competition, and it will not be the last word.

As I stated earlier, we are searching for the perfect mixture of competition and regulation. But U.S. electricity markets are highly dynamic, and if we achieve that perfect mixture, the market will change and require a further adjustment in policy.

U.S. policy supporting competitive wholesale power markets will not change. With that in mind, our focus at FERC is making wholesale markets more competitive.

There are two great challenges facing U.S. electricity markets – security of electricity supply and climate change. I would like to discuss how the U.S. is addressing these challenges.

Competition policy has assured security of U.S. electricity supply at a reasonable cost for 25 years, and independent power producers have accounted for most generation additions during this period.

The U.S. is poised on the edge of a large generation build, perhaps larger than the generation build between 1996 and [2004]. The U.S. also needs significant investment in our transmission and distribution infrastructure. The cost of new generation will likely be higher than installed generation.

As we confront the security of supply challenge, there are some threshold questions. Will the U.S. build enough additional electricity supply? Who will build? What will we build – what will the generation mixture of our new electricity supply be?

I believe the United States will build enough electricity supply to meet demand, but probably not as much as we should, and reserve margins may tighten.

With respect to "Who will build?" I believe the answer will vary by region. In some regions, vertically integrated utilities may account for most new electricity supply additions. In other regions, the answer may be independent power producers. This reflects the hybrid nature of U.S. wholesale power markets.

The answer to 'What will be built?' may be more natural gas fired generation than is ideal, at least over the next ten years. Natural gas has many advantages as a primary fuel for electric generation, but dependence on a single fuel for incremental electricity supply can run great risks. In the past 18 months, 54 percent of the coal generating capacity ordered since 2000 has been cancelled. There has been a revival of interest in nuclear generation, but additional nuclear units are unlikely to be operating within the next ten years. Wind generation produces a different product than a baseload coal plant, and wind cannot substitute easily for cancelled coal power plants.

The end result is the U.S. is likely to rely very heavily on natural gas for generation additions over the next ten years. That may place upward pressure on electricity prices.

The last dash for gas for power generation took place when natural gas prices were low. A new dash for gas would occur when gas prices are relatively high. This new dash for gas would not be driven by low prices, but by the prospect of change in U.S. climate change policy. Given the tremendous regulatory uncertainty regarding new coal projects, and the length of nuclear plant licensing and construction, gas may be the best baseload option for new generation additions over the next ten years.

This has important energy policy implications. It is important to recognize that climate change is not just environmental policy – it is also energy policy. At one level, climate change policy involves decisions regarding the size of U.S. electricity supply and the fuel mixture used to generate that supply.

There are many options on how to approach climate change. Some approaches may be sound energy policy, some may be acceptable energy policy. But others may be profoundly unwise or reckless energy policy.

It is essential to balance energy and environmental policy as the U.S. confronts climate change.

In conclusion, the U.S. is committed to competition policy. There will be no change in policy. Our focus is on strengthening wholesale competitive markets, through steady reform, and our goal is perfect competition. And we believe that competitive markets are best suited to meet the security of supply and climate change challenges."

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Los Angeles Times

http://www.latimes.com/news/nationworld/la-na-coal18jan18,1,2092714.story
From the Los Angeles Times

Coal is no longer on front burner

The rush to build power plants slows as worries grow over global warming, building costs and transportation.

By Judy Pasternak
Los Angeles Times Staff Writer

January 18, 2008

WASHINGTON — America's headlong rush to tap its enormous coal reserves for electricity has slowed abruptly, with more than 50 proposed coal-fired power plants in 20 states canceled or delayed in 2007 because of concerns about climate change, construction costs and transportation problems.

Coal, touted as cheap and plentiful, has been a cornerstone of President Bush's plans to meet America's energy needs with dozens of new power plants. Burned in about 600 facilities, coal produces more than half of the nation's electricity.

FOR THE RECORD:
Coal plants: A story in Friday's Section A about postponed and canceled coal-fired power plants said that cargo ships were carrying 6,000 to 9,000 pounds less coal than their capacity in order to stay afloat in shallow Great Lakes channels. The ships are carrying 6,000 to 9,000 tons less than their capacity. In addition, a map that accompanied the story labeled the state of Michigan as Wisconsin. The location of a proposed coal-fired power plant indicated on the map is, in fact, in Michigan. —

But urgent questions are emerging about a fuel once thought to be the most reliable of all. Utilities are confronting rising costs and a lack of transportation routes from coal fields to generators, opposition from state regulators and environmental groups, and uncertainty over climate-change policies in Washington.

"Coal projects need more regulatory certainty before any new ones are going to get built in the near future," said David Eskelsen, a spokesman for PacifiCorp, which serves more than 1.6 million customers in six Western states. "The current situation does make utility planning very challenging."

Just a few weeks ago, PacifiCorp dropped plans for two coal-fired power plants in Utah, citing the many unknowns in assessing the costs and objections on global warming grounds from a major customer: the city of Los Angeles. PacifiCorp said in filings with the state of Utah that it hadn't found a substitute for production that it will need to bring online in 2012 and 2014.

Shortages are feared

The setbacks have energy regulators jittery about the prospects for meeting America's ever-increasing hunger for electricity. They say that any delays in building new capacity -- coal-fired or otherwise -- add pressure to an already strained electricity infrastructure, raising the prospect of shortages or sharply higher prices.

Energy planners say coal needs to be in the mix because the other mainstay fuels for generating electricity also have serious drawbacks. Natural gas has proved volatile in both price and supply. Nuclear power plants are costly and take much longer to build -- and the problem of radioactive-waste disposal remains unsolved.

"We're very close to the edge," said Rick Sergel, who keeps a close eye on the grid as chief executive of the quasi-governmental North American Electric Reliability Corp. "We operate under tight conditions more often than ever. We need action in the next year or two to start on the path to having enough electricity 10 years from now."

This fall, regulators in Kansas and Washington state denied applications for coal plant permits because of concerns about carbon dioxide emissions.

After Republican Florida Gov. Charlie Crist said in October that he wasn't a "fan" of coal, utilities postponed plans to build coal plants in Tampa and Orlando.

Xcel Energy has told Colorado officials that it plans to close two coal plants and add 1,000 megawatts of wind and solar power, in addition to a new natural-gas plant. The company wants to cut its carbon dioxide emissions 10% by 2015.

In Nevada, Sierra Pacific Resources delayed construction of a coal plant and moved up the schedule for a natural-gas-powered plant instead.

The Tennessee Valley Authority decided in August to add a $2.5-billion unit to a nuclear power plant rather than construct a new coal facility -- the other main option -- because of the uncertain economics.

Altogether, 53 coal-fired plants were canceled or delayed in 2007, according to Global Energy Decisions, a private consulting firm that tracks power plants for the Department of Energy.

In the near term, coal clearly will remain a part of the American energy picture. Even as the postponements and terminations pile up, plans for new coal-fired power plants continue to advance in New Mexico, Mississippi and Indiana.

Although TXU Energy canceled eight coal-fired power plants it had proposed in Texas, the utility is going ahead with three others.

Last month, an energy industry consortium announced plans to build a government-subsidized power plant in southern Illinois to demonstrate low-emissions coal technology. But the ballooning cost of the FutureGen plant -- now projected to be about $1.8 billion, nearly double its original estimated price tag -- has drawn criticism from the Department of Energy, which could delay or kill the project by withholding funds.

The growing push in Washington to do something about global warming is a major factor that affects the cost of burning chunks of solid carbon, by far the dirtiest way to manufacture power.

A recent study by the industry-funded Electric Power Research Institute projects that coal power will cost more than nuclear power or natural gas by 2030 if coal's carbon dioxide problem is solved the way most experts envision. Still unproven, that method involves separating carbon dioxide from the gas stream before it heads out of the stacks, collecting the vapors and then storing them underground. That would also require a new network of pipelines to move carbon dioxide from the power plant to a geologically sound site.

Another industry analysis predicts that wholesale electricity prices will rise 35% to 65% by 2015 if the Warner-Lieberman climate change bill -- one of the more conservative plans put forward in the Senate -- is enacted.

A more immediate challenge is transportation, from missing links in the rail routes to silted-up Great Lakes shipping channels, which raise concerns that coal may not be so simple to get at after all.

"Can coal deliver?" asked Gary Hunt, president of Global Energy Advisors, a Sacramento-based unit of Global Energy Decisions. "The answer is no," he said -- not without "billions and billions" spent on improvements for mining capacity, railroads and shipping.

Powder River Basin

About 40% of the coal that America burns comes from the Powder River Basin in Wyoming and Montana. Sought after for its low sulfur content, the product is sent all over the country on trains more than 100 cars long. But only two rail companies serve the basin, and for 100 miles they share one set of tracks.

That caused trouble in spring 2005, when coal dust built up between the ties, snow and rain fell on the tracks, and the resulting slush caused two derailments. The ensuing bottleneck delayed coal deliveries for months. Utilities started hoarding the coal they had on hand, and ran their more expensive natural-gas plants more often. They filed for rate hikes, and at least two sued their rail carriers.

Railroads are investing about $200 million to improve and expand the tracks leading out of the Powder River Basin, and they point to record cargoes this year. But the National Mining Assn. still has concerns about the future, spokesman Luke Popovich said. "Capacity is adequate now, but it's close to being inadequate," he said.

In the coal fields of southern Illinois and Indiana, a mining renaissance is hoped for -- but no north-south rail line connects them with Chicago and the Great Lakes.

Purdue University recommends building a 300-mile "Indiana coal corridor" -- at a cost of about $1 million a mile.

Overall, the Assn. of American Railroads estimates that $148 billion needs to be invested in freight infrastructure over the next 28 years. The industry says it needs federal assistance to help it cover about $39 billion of that cost.

We Energies, which provides electricity in Wisconsin and Michigan, said it had faced at least $45 million in higher fuel costs as a result of rail disruptions. Like other producers in the Upper Midwest, the company tried to find relief by shipping coal across the Great Lakes. But lake channels have silted up, creating a "dredging crisis," in the words of James H.I. Weakley, president of the Lake Carriers' Assn.

The Lake Erie port of Dunkirk, N.Y. -- site of a coal-fired power plant -- closed to shipping in 2005. A freighter ran aground at the Lake Huron port of Saginaw, Mich., last year. With ships loading 6,000 to 9,000 pounds less than their capacity in order to stay afloat in the shallower channels, coal-cargo totals on the lakes this year are down 8% from a year ago, the carriers' group said.

The domestic transport problem has led some coal customers to look overseas for supplies. Despite the promotion of coal as crucial to energy independence, imports have been rising since 2003. For example, Southern Co., the largest power supplier in the Southeast, brings in nearly 19% of its supply through East Coast ports from Colombia, Venezuela and Russia, said W. Paul Bowers, president of generation and energy marketing.

Coal's advocates say they are still optimistic about the future, because America has 200 years' worth of reserves -- and growing electricity needs. "If you don't want to use coal," asks Janet Gellici, executive director of the American Coal Council, "which 12 hours of the day don't you want electricity?"

Decisions up in the air

In any case, coal producers say, surging worldwide demand, especially from China and India, indicates there will be a healthy global market for their product. Indeed, that demand has helped drive up the cost of coal, which has been at record levels for much of 2007, which in turn drives up the potential cost of coal-fired energy.

The changing coal picture is making it hard for America's energy planners. Decisions about where power plants are located and when they are built can also determine where -- and whether -- new transmission corridors are built. And that could create spillover effects that hurt the availability of cleaner sources, like wind, that would use the same lines.

With power plant decisions up in the air, there's been a lag in seeking new transmission lines, said Suedeen Kelly, who sits on the Federal Energy Regulatory Commission. And because the transmission lines -- like power plants -- take years to move from the proposal stage to operations, "ideally, you should be starting to build these transmissions lines today," Kelly said.

It's tough for those who would build power plants to make billion-dollar commitments that will last for the next 50 years while trying to guess what's going to happen in Washington. The White House, the Senate and the House of Representatives are sharply divided over versions of global warming legislation that could provide answers.

The president's threat to veto the energy bill forced congressional Democrats to drop a requirement for utilities to meet targets for use of renewable energy, such as solar and wind power.

Bush has also signaled that he'll reject any global warming legislation that includes mandatory carbon limits. The proposals are controversial in Congress as well.

This could mean at least another year of jousting -- and another year of indecision.

For environmentalists, a pause in the rush to coal is a good thing.

"It's the silver lining" in an otherwise clouded energy picture, said Bruce Nilles, who heads the Sierra Club's National Coal Campaign.

More important is which energy sources utilities turn to in its place, he said.

"That's what this is all about: whether they stick with the old way or we transition to a new, clean way of making energy."

judy.pasternak@latimes.com

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Coal: America's Energy Future

VOLUME II
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Commercial Combustion-Based Technologies

Combustion technology choices available today for utility scale power generation include circulating fluidized bed (CFB) steam generators and pulverized coal (PC) steam generators utilizing air for combustion. Circulating fluidized beds are capable of burning a wide range of low-quality and low-cost fuels. The largest operating CFB today is 340 Megawatts (MW), although units up to 600 MW are being proposed as commercial offers. Pulverized coal-fired boilers are available in capacities over 1000 MW and typically require better quality fuels.

Advanced Pulverized Coal Combustion (PC) Technology

Pulverized Coal Process Description

In a pulverized coal-fueled boiler, coal is dried and ground in grinding mills to face-powder fineness (less than 50 microns). It is transported pneumatically by air and injected through burners (fuel-air mixing devices) into the combustor. Coal particles burn in suspension and release heat, which is transferred to water tubes in the combustor walls and convective heating surfaces. This generates high temperature steam that is fed into a turbine generator set to produce electricity.

In pulverized coal firing, the residence time of the fuel in the combustor is relatively short, and fuel particles are not recirculated. Therefore, the design of the burners and of the combustor must accomplish the burnout of coal particles during about a two-second residence time, while maintaining a stable flame. Burner systems are also designed to minimize the formation of nitrogen oxides (NO_X) within the combustor.

The principal combustible constituent in coal is carbon, with small amounts of hydrogen. In the combustion process, carbon and hydrogen compounds are burned to carbon dioxide (CO_2) and water, releasing heat energy. Sulfur in coal is also combustible and contributes slightly to the heating value of the fuel; however, the product of burning sulfur is sulfur oxides, which must be captured before leaving the power plant. Noncombustible portions of coal create ash; a portion of the ash falls to the bottom of the furnace (termed bottom ash), while the majority (80 to 90%) leaves the furnace entrained in the flue gas.

Pulverized coal combustion is adaptable to a wide range of fuels and operating requirements and has proved to be highly reliable and cost-effective for power generation. Over 2 million MW of pulverized coal power plants have been operated globally.

After accomplishing transfer of heat energy to the steam cycle, exhaust flue gases from the PC combustor are cleaned in a combination of post combustion environmental controls. These environmental controls are described in detail in further sections. A schematic of a PC power plant is shown in Figure 1.1.

Schematic Illustration of a Pulverized Coal-Fired Utility Boiler

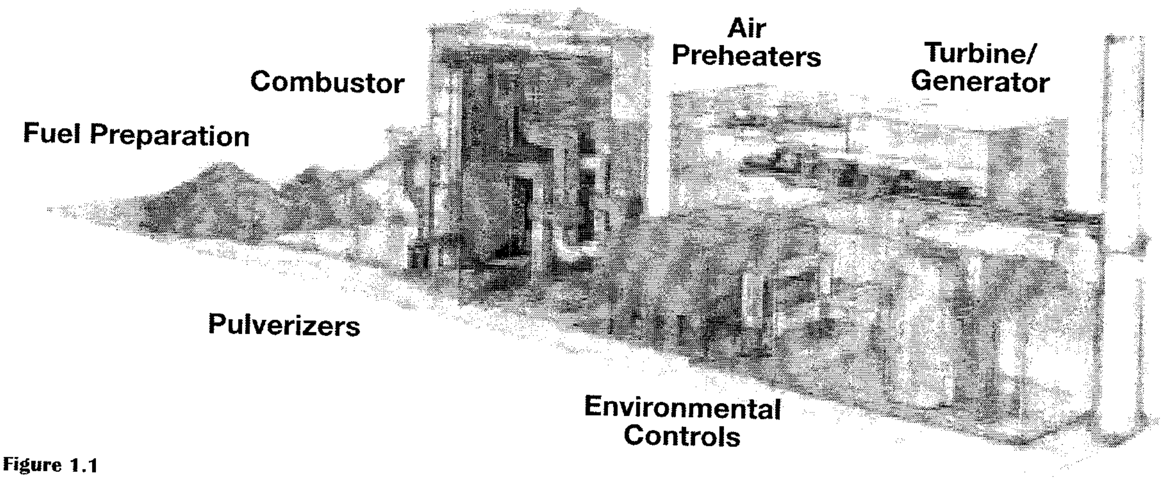

Figure 1.1

Fluidized Bed Combustion

Fluidized Bed Combustion Process Description

In a fluidized bed power plant, coal is crushed (rather than pulverized) to a small particle size and injected into a combustor, where combustion takes place in a strongly agitated bed of fine fluidized solid particles. The term "fluidized bed" refers to the fact that coal (and typically a sorbent for sulfur capture) is held in suspension (fluidized) by an upward flow of primary air blown into the bottom of the furnace through nozzles and strongly agitated and mixed by secondary air injected through numerous ports on the furnace walls. Partially burned coal and sorbent is carried out of the top of the combustor by the air flow. At the outlet of the combustor, high-efficiency cyclones use centrifugal force to separate the solids from the hot air stream and recirculate them to the lower combustor.

This recirculation provides long particle residence times in the CFB combustor and allows combustion to take place at a lower temperature. The longer residence times increase the ability to efficiently burn high moisture, high ash, low-reactivity, and other hard-to-burn fuel such as anthracite, lignite, and waste coals and to burn a range of fuels with a given design.

CFB technology incorporates primary control of NO_X and sulfur dioxide (SO_2) emissions within the combustor. At CFB combustion temperatures, which are about half that of conventional boilers, thermal NO_X is close to zero. The addition of fuel/air staging provides maximum total NO_X emissions reduction. For sulfur control, a sorbent is fed into the combustor in combination with the fuel. The sorbent is fine-grained limestone, which is calcined in the combustor to form calcium oxide. This calcium oxide reacts with sulfur dioxide gas to form a solid, calcium sulfate. Depending on the fuel and site requirements, additional NO_X and SO_2 environmental controls can be added to the exhaust gases. With this combination of environmental controls, CFB technology provides an excellent option for low emissions and very fuel-flexible power generations.

CFB technology has been an active player in the power market for the last two decades. Today, over 50,000 MW of CFB plants are in operation worldwide.

Advanced Steam Cycles for Clean Coal Combustion

Improving power plant thermal efficiency will reduce CO_2 emissions and conventional emissions such as SO_2, NO_X and particulate by an amount directly proportional to the efficiency improvement. Efficiency improvements have been achieved by operation at higher temperature and pressure steam conditions and by employing improved materials and plant designs. The efficiency of a power plant is the product of the efficiencies of its component parts. The historical evolutionary improvement of combustion-based plants is traced in Figure 1.2. As shown, steam cycle efficiency has an important effect upon the overall efficiency of the power plant.

Current Coal-Fired Power Plant Improvements

Rankine cycle efficiency improvement from 34% to 58% (LHV)

Due to:
- Regenerative feedwater preheating
- Increase of steam pressure and temperature
- Reheat

Steam turbine efficiency improvement from 60% to 92%

Due to:
- Blade design
- Reheat
- Increase in steam pressure and temperature
- Shaft and inter-stage seals
- Increase in rating

Generator efficiency improvement from 91% to 98.7%

Due to:
- Increase in rating
- Improved cooling (hydrogen/water)

Boiler efficiency improvement from 83% to 92% (LHV)

Due to:
- Pulverized coal combustion with low excess air
- Air preheat
- Reheat
- Size increase

Auxiliary efficiency improvement from 97% to 98%

Due to:
- Increase in component efficiencies
- Size increase

Auxiliary efficiency decrease from 98% to 93%

Due to:
- More boiler feed pump power
- Power and heat for emission-reduction systems

Power plant net efficiencies:

η Power Plant = η Rankine Cycle x η Turbine x η Generator x η Boiler x η Auxiliaries
η Early Power Plant = 34% x 60% x 91% x 83% x 97% = 15%
η Today's Power Plant = 58% x 92% x 98.7% x 92% x 93% = 45% (LHV)

Note: Efficiency is usually expressed in percentages. The fuel energy input can be entered into the efficiency calculation either by the higher (HHV) or the lower (LHV) heating value of the fuel. However, when comparing the efficiency of different energy conversion systems, it is essential that the same type of heating value is used. In U.S. engineering practice, HHV is generally used for steam cycle plants and LHV for gas turbine cycles. In European practice efficiency calculations are uniformly LHV-based. The difference between HHV and LHV for a bituminous coal is about 5%, but for a high-moisture low-rank coal, it could be 8% or more.

Figure 1.2 Source: Termuehlen and Empsperger 2003

As steam pressure and superheat temperature are increased above 225 atm (3308 psi) and 374.5°C (706°F), respectively, the steam becomes supercritical (SC); it does not produce a two phase mixture of water and steam but rather undergoes a gradual transition from water to vapor with corresponding changes in physical properties. In order to avoid unacceptably high moisture content of the expanding steam in the low pressure stages of the steam turbine, the steam, after partial expansion in the turbine, is taken back to the boiler to be reheated. Reheat, single or double, also serves to increase the cycle efficiency.

Pulverized coal fired supercritical steam cycles (PC/SC) have been in use since the1930s, but material developments during the last 20 years, and increased interest in the role of improved efficiency as a cost-effective means to reduce pollutant emission, resulted in an increased number of new PC/SC plants built around the world. After more than 40 years of operation, supercritical technology has evolved to designs that optimize the use of high temperatures and pressures and incorporate advancements such as sliding pressure operation. Over 275,000 MW of supercritical PC boilers are in operation worldwide.

Supercritical steam parameters of 250 bar 540°C (3526psi/1055°F) single or double reheat with efficiencies that can reach 43 to 44 % (LHV) (39 to 40% HHV) represent mature technology. These SC units have efficiencies two to four points higher than subcritical steam plants representing a relative 8 to 10% improvement in efficiency. Today, the first fleet of units with Ultra Supercritical (USC) steam parameters of 270 to 300 bar and 600/600°C (4350 psi, 1110°/1110°F) are successfully operating, resulting in efficiencies of >45% (LHV) (40 to 42% HHV), for bituminous coal-fired power plants. These "600°C" plants have been in service more than seven years, with excellent availability. USC steam plants in service or under construction during the last five years are listed in Figure 1.3.

USC Steam Plants in Service or Under Construction Globally

Power Station	Cap. MW	Steam Parameters	Fuel	Year of Comm.	Eff% LHV
Matsuura 2	1000	255bar/598°C/596°C	PC	1997	
Skaerbaek 2	400	290bar/580°C/580°C/580°C	NG	1997	49
Haramachi 2	1000	259bar/604°C/602°C	PC	1998	
Nordjyland 3	400	290bar/580°C/580°C/580°C	PC	1998	47
Nanaoota 2	700	255bar/597°C/595°C	PC	1998	
Misumi 1	1000	259bar/604°C/602°C	PC	1998	
Lippendorf	934	267bar/554°C/583°C	Lignite	1999	42.3
Boxberg	915	267bar/555°C/578°C	Lignite	2000	41.7
Tsuruga 2	700	255bar/597°C/595°C	PC	2000	
Tachibanawan 2	1050	264bar/605°C/613°C	PC	2001	
Avedere 2	400	300bar/580°C/600°C	NG	2001	49.7
Niederaussen	975	290bar/580°C/600°C	Lignite	2002	>43
Isogo 1	600	280bar/605°C/613°C	PC	2002	
Neurath	1120	295bar/600°C/605°C	Lignite	2008	>43%

Figure 1.3 Source: Blum and Hald and others

Looking forward, advancements in materials are important to the continued evolution of steam cycles and higher efficiency units. Development programs are under way in the United States, Japan and Europe, including the THERMIE project in Europe and the Department of Energy/Ohio Cooperative Development Center project in the United States, which are expected to result in combustion plants that operate at efficiencies approaching 48% (HHV) (Figure 1.4). Advanced materials development will be critical to the success of this program.

Ongoing Development for USC Steam Plants

	Japan – NIMS Materials Development	**U.S. – DOE Vision 21**	**Europe – THERMIE AD700**
	1997–2007	**2002–2007**	**1998–2013**
Development Requirements	Ferritic steel for 650°C	Materials development and qualification Target: 350 bar, 760°C, (870°C)	Materials development and qualification Componentdesign and demonstration Plant demon stration Target: 400 –1000 MW, 350 bar, 700°C, 720°C

Figure 1.4 Source: Blum and Hald

Figure 1.5 summarizes the evolution of efficiency for supercritical PC units. It should be noted that commercial offerings for supercritical CFBs have been made in the last two years and that the first SCCFB units will be commissioned in the next 2 to 3 years.

Estimated Plant Efficiencies for Various Steam Cycles

Description	Cycle	Reported at European Location (LHV)	Converted to U.S. Practice(2) (HHV)
Subcritical–commercial	16.8 MPa/558°C/538°C		37
Supercritical–mature	24.5 MPa/565°C/565°C/565°C(1)		39–40
ELSAM (Nordjyland 3)	28.9 MPa/580°C/580°C/580°C	47/44	41
State of the Art Supercritical–commercial	31.5 MPa/593°C/593°C/593°C(1)		40–42
THERMIE–future	38 MPa/700°C/720°C/720°C	50.2/47.7	46/43
EPRI/Parson–future	37.8 MPa/700°C/700°C/700°C		44
DOE/OCDO	38.5 MPa/760°C/760°C		46.5
USC Project–future	38.5 MPa/760°C/760°C/760°C		47.5–48

1. Eastern bituminous Ohio coal. Lower heating value, LHV, boiler fuel efficiency is higher than higher heating value, HHV, boiler fuel efficiency. For example, an LHV net plant heat rate at 6205.27 Btu/kWh with the LHV net plant efficiency of 55% compares to the HHV net plant heat rate at 6494 Btu/kWh and HHV net plant efficiency of 52.55%.
2. Reported European efficiencies are generally higher compared to those in the United States due to differences in reporting practice (LHV vs. HHV), coal quality, auxiliary power needs, condenser pressure and ambient temperature, and many other variables. Numbers in this column for European project numbers are adjusted for U.S. conditions to facilitate comparison.

Figure 1.5 Source: P. Weitzel, and M. Palkes

The effect of plant efficiency upon CO_2 emissions reduction is shown in Figure 1.6.

It is estimated that during the present decade 250 gigawatts (GW) of new coal-based capacity will be constructed. If more efficient SC technology is utilized instead of subcritical steam, CO_2 emissions would be about 3.5 gigaton (Gt) less during the lifetime of those plants, even without installing a system to capture CO_2 from the exhaust gases.

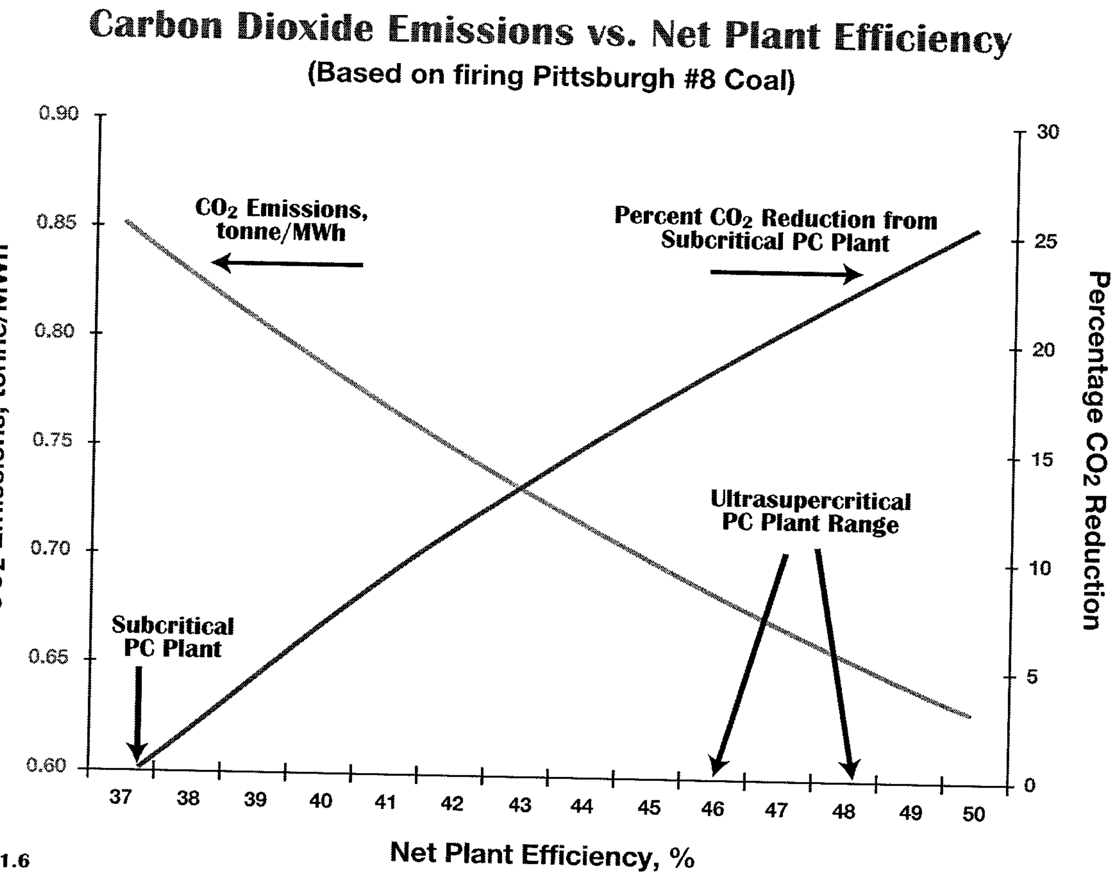

Figure 1.6

Environmental Control Systems for Combustion-Based Technologies

In all clean-coal technologies, whether combustion- or gasification-based, entrained ash and trace contaminants and acid gases must be removed from either the flue gas or syngas. Different processes are used to match the chemistry of the emissions and the pressure/temperature and nature of the gas stream.

PC/CFB plants can comply with tight environmental standards. A range of environmental controls are integrated into the combustion process (low NO_X burners for PC, sorbent injection for CFB) or employed post combustion to clean flue gas. The following sections describe the state of the art for emissions controls for combustion technologies. In general, these environmental processes can be applied as retrofit to older units and designed into new units. In some cases, performance will be better on a new unit since the design can be optimized with the new plant.

Figure 1.7 illustrates the comprehensive manner in which combustion and post-combustion controls combine to minimize formation and maximize capture of emissions from clean-coal combustion.

Recent Air Permit Limits

POLLUTANT	CONTROL TECHNOLOGY	EMISSIONS LIMIT	AVERAGING TIME	PERMITTED FACILITIES
Carbon Monoxide (CO)	Good Combustion Practices	.10 lb/MBtu	3-day rolling average, excluding start up (SU)/ shut down (SD)	Thoroughbred, Trimble County II, others
Nitrogen Oxides (NO_x)	Low NO_X Burners and Selective Catalytic Reduction	.05 lb/MBtu <2 ppmdv Ammonia	30-day rolling average, excluding SU/SD	CPS San Antonio, Trimble County II
Particulate Matter (PM)	Fabric Filter Baghouse, Flue Gas Desulfurization, Wet ESP	.018 lb/MBtu 20% Opacity	Based on a 3-hour block average limit, includes condensables	Thoroughbred, Elm Road
Particulate matter <10 microns ($PM_{<10}$)	Fabric Filter Baghouse, Flue Gas Desulfurization, Wet ESP	.018 lb/MBtu 20% Opacity	Based on a 3-hour block average limit, includes condensables	Trimble County II
Sulfur Dioxide (SO_2)	Washed Coal and Wet Flue Gas Desulfurization	.1 lb/MBtu 98% Removal	30-hour rolling average, including SU/SD	Trimble County II
Volatile Organic Compounds (VOC)	Low NO_X Burners and Good Combustion Practices	.0032/lb MBtu	24-hour rolling average excluding SU/SD	Trimble County II
Lead (Pb)	Fabric Filter Baghouse, Flue Gas Desulfurization	3.9 lb/TBtu	Based on a 3-hour block average limit	Thoroughbred
Mercury (Hg)	Fabric Filter Baghouse, Flue Gas Desulfurization	1.12 lb/TBtu (Based on 90% Removal, Final Limit is Operational Permit)	Stack testing, coal sampling & analysis	Elm Road
Beryllium (Be)	Fabric Filter Baghouse, Flue Gas Desulfurization	9.44×10^{-7} lb/MBtu	Stack testing, coal sampling & analysis	Thoroughbred
Fluorides (F)	Fabric Filter Baghouse, Flue Gas Desulfurization	0.000159 lb/MBtu	Stack testing, coal sampling & analysis	Thoroughbred
Hydrogen Chloride (HCl)	Flue Gas Desulfurization	6.14 lb/hr	Stack testing based on a 24-hour rolling average	Thoroughbred
Sulfuric Acid Mist (H_2SO_4)	Flue Gas Desulfurization and Wet ESP	.004 lb/MBtu	.004 lb/MBtu	Trimble County II

Figure 1.7

Overview of Nitrogen Oxides

Nitrogen oxides are byproducts of the combustion of virtually all fossil fuels. The formation of NO_X in the combustion process is a function of two reactions/sources—thermal NO_X originates from the nitrogen found in the air used for combustion, and fuel NO_X originates from organically bound nitrogen found at varied levels in all coals. Control of NO_X emissions is accomplished in PC/CFB units through a combination of in-furnace control of the combustion process and post-combustion reduction systems.

Combustion NO_X Control

Advanced low NO_X PC combustion systems, widely used today in utility and industrial boilers, provide dramatic reductions in NO_X emissions in a safe, efficient manner. These systems have been retrofitted to many existing units and are reducing NO_X emissions to levels that in some cases rival the most modern units. The challenges are considerable, given that the older units were not built with any thought of adding low NO_X systems in the future. Low NO_X combustion systems can reduce NO_X emissions by up to 80% from uncontrolled levels, with minimal impact on boiler operation, and they do so while regularly exceeding 99% efficiency in fuel utilization. Low NO_X firing systems are standard equipment on new PC units.

Advanced low NO_X systems start with fuel preparation that consistently provides the necessary coal fineness while providing uniform fuel flow to the multiple burners. Low NO_X burners form the centerpiece of the system, and are designed and arranged to safely initiate combustion and control the process to minimize NO_X. An overfire air (OFA) system supplies the remaining air to complete combustion while minimizing emissions of NO_X and unburned combustibles. Distributed control systems (DCS) manage all aspects of fuel preparation, air flow measurement and distribution, and flame safety and also monitor emissions. Cutting-edge diagnostic and control techniques, using neural networks and chaos theory, assist operators in maintaining performance at peak levels.

For pulverized coal units, uncontrolled NO_X emissions from older conventional combustion systems typically range from 0.4 to 1.6 lb/106 Btu, dependent on the original system designs. Retrofitting of low NO_X PC combustion systems is capable of reducing NOx down to 0.15 to 0.5 lb/106 Btu exiting the combustor; the performance is highly dependent on the fuel and the ability to modify the existing boiler design. The goal of the DOE's low NO_X burner program is to develop technologies for existing plants with a NO_X emission rate of 0.15 lb/10^6 Btu by 2007 and 0.10 lb/10^6 Btu by 2010, while achieving a levelized cost savings of at least 25% compared to state-of-the-art selective catalytic reduction (SCR) control technology.

New plants which can be designed for optimized reduction of NO_X in the firing systems which will achieve combustor outlet levels at the lower end of this range and designs are in demonstration to drive combustor outlet NO_X levels to 0.1 lb/MMBtu.

Combustion NO_X Control Costs

The installed cost of a low NO_X combustion system retrofit on a coal-fired unit is in the range of $7 to $15/kW to achieve NO_X reductions of 20 to 70%. Installation of low NO_X firing systems is standard procedure on new units, and the cost is embedded in the firing system cost of the new unit design.

The industry continues to aggressively develop improvements to low NO_X burner technology to lessen the NO_X reduction requirements of the post-combustion NO_X control equipment (selective catalytic reduction), which can significantly reduce capital and operating costs.

Post Combustion NO_X Control – SCR and SNCR

Advanced PC/CFB plants utilize a combination of combustion and/or post-combustion control for high levels of NO_X reduction. PC plants generally combine low NO_X firing with selective catalytic reduction (SCR) to reduce NO_X emissions, while CFB units utilize selective non-catalytic reduction (SNCR).

SCR systems use a catalyst and a reductant (typically ammonia) to dissociate NO_X to harmless nitrogen and water. The SCR catalytic-reactor chamber is located at the outlet of the combustor, prior to the air heater inlet. Ammonia is injected upstream of the SCR; the ammonia/flue gas mixture enters the reactor, where the catalyst reaction is completed. SCR technology is capable of reducing NO_X emissions entering the system by 80 to 90%. SCR technology has been applied to coal-fired boilers since the 1970s; installations are successfully in operation in Japan, Europe and the United States.

Depending on the fuel, CFB units may also incorporate post combustion NO_X control. Typically CFB would utilize a chemical process called selective non-catalytic reduction (SNCR) to reduce NO_X. In SNCR, a reagent (either ammonia or urea) is injected in the flue gas and reacts with the NO_X to form nitrogen and ammonia. No catalyst is used, and it is necessary to design the injection to provide for adequate residence time, good mixing of the reagent with the flue gas and temperature, and a suitable temperature window (1600°–2100°F) to drive the reaction. SNCR is capable of reducing NO_X emissions entering the system by 70 to 90% and is a proven and reliable technology that was first applied commercially in 1974.

SO_X Overview

All coals contain sulfur (S), which, during combustion, is released and reacts with oxygen (O_2) to form sulfur dioxide, SO_2. A small fraction, 0.5 to 1.5%, of the SO_2 will react further with O_2 to form sulfur trioxide (SO_3). If an SCR is installed for NO_x control, the catalyst may result in an additional 0.5 to 1.0% oxidation of SO_2 to SO_3. Both SO_2 and SO_3 are precursors to acid rain.

The most prevalent technologies for SO_2 reduction in the U.S. power generation market are wet scrubbing, or wet flue gas desulfurization (WFGD) and spray dryer absorption (SDA). Wet scrubbers can easily achieve 98% to over 99% SO_2 removal efficiency on any type of coal. Other technologies that have been employed to a minor extent include dry sorbent injection and dry fluidized-bed scrubbers.

All recent, new coal-fired generating plants include either WFGD or SDA technologies for SO_X emissions control. The technology selection is dependent on the coal characteristics, the emission limit requirements, and site-specific factors, which may include restrictions on water availability and space limitations. WFGD is typically used when the expected range of coal sulfur content will exceed approximately 1.5%. However, SDA technology has been applied across the full range of coal ranks.

The U.S. utility industry is experiencing a surge of WFGD system retrofits at existing generating stations in response to Clean Air Interstate Rule (CAIR) and other state or federal legislation. Approximately 38,000 MW of WFGD systems are currently in various stages of design and construction. WFGD systems dominate the coal-fired utility industry with approximately 80 to 85% of the total installed SO_2 emissions control systems.

SDA technology has been selected for emissions control on more than 3,500 MW of new coal-fired generators completed in the last five years or currently under construction, as well as more than 1,500 MW of retrofit installations. The SDA technology consumes significantly less water than WFGD and is often a choice where water usage is restricted.

Technical Description: Wet Scrubbers (WFGD)

Wet scrubbers are large vessels in which the flue gas from the combustion process is contacted with a reagent. The reagent is typically limestone or lime mixed with water to form a slurry. The reagent is added to the scrubber in a reaction tank located at the bottom of the scrubber. Slurry from the reaction tank is pumped to a spray zone and sprayed into the gas inside the scrubber. This slurry is a combination of reaction products, fresh reagent and inert material. The SO_2 is absorbed into the slurry, reacts with the reagent, and forms a solid reaction product. A portion of the recirculated slurry is pumped to a dewatering system where the slurry is concentrated to 50 to 90% solids. The water is returned to the scrubber. The most common reagent for wet scrubbing is limestone, although there are a number of units that use lime or magnesium-enriched lime.

Peformance: WFGD

Wet scrubbers can easily achieve 98% to over 99% SO_2 removal efficiency on any type of coal.

Direction of Technology Development: WFGD

The development of wet scrubbers is in the optimization stage to drive incremental removal to more than 99% and to reduce capital and operating cost. This includes developing methods for reduction in power and reagent consumption. Also, better methods for reducing moisture carryover and lowering the filterable particulate leaving the scrubber are important.

There is work in developing multi-emissions control systems that optimize the design of post-combustion controls and integrate the capture processes for NO_X, particulate, SO_2 and mercury. In addition, innovations in wet scrubbing include a design that uses the air stream used for forced oxidation to develop the recirculated flow of slurry in the scrubber. Also, work is being done on high-velocity designs to reduce the size of WFGD.

Technical Description: Spray Dryer Absorption (SDA)

SDA differs from WFGD in that it does not completely quench and saturate the flue gas. A reagent slurry is sprayed into the reaction chamber at a controlled flow rate that quenches the gas to about 30°F above the saturation temperature. An atomizer is used to break up the reagent slurry into fine drops to enhance SO_2 removal and drying of the slurry. The water carrying the reagent slurry is evaporated leaving a dry product. The gas then flows to a fabric filter (FF) or electrostatic precipitators (ESP) for removal of the reaction products and fly ash. There is also significant SO_2 and other acid gas removal in the fabric filter due to the reaction of SO_2 with the alkaline cake on the filter bags. Fresh lime slurry is mixed with a portion of the fly ash and reaction products captured in the particulate collector downstream of the SDA to form the reagent slurry.

SDA is considered best available control technology (BACT) for sub-bituminous coal-fired generating stations. State-of-the-art application of the technology involves one or more SDA modules each with a single, high-capacity atomizer to introduce the reagent slurry to the flue gas followed by a pulse-jet fabric filter for collection of the solid byproduct. Demonstrated long-term availability and reliability of the system have eliminated the need for including spare-module capacity in the design.

SDA technology has also been applied as a polishing scrubber following CFBs to achieve overall SO_2 emissions reduction of 98 to 99%. Retrofit of SDA/FF systems on existing boilers is a cost-effective means to achieve significant emissions reduction.

Performance: SDA

Performance guarantees for SDA systems are typically in the range of 93 to 95% SO_2 removal for coals with up to 1.5% sulfur content. Higher removal efficiencies have been guaranteed and demonstrated in practice. An SDA/FF system with a fabric filter can typically achieve >95% removal of H_2SO_4 with 0.004 lb/MMBtu as a typical emission limit. Emission limits for the acid gases HCl and HF as well as trace metals are also typically provided.

Direction of Technology Development: SDA

SDA is also a mature technology for SO_2 emissions control. Technology development efforts are focused on integrating operating experiences from existing installations to:

- extend maintenance intervals by introducing new wear materials and process design features;
- reduce reagent consumption by enhancing process monitoring and optimizing lime slaking;
- enhance operating flexibility to respond to process upsets;
- enhance maintenance access; and
- optimize trace element and acid gas emission control performance.

Development efforts are also in progress to extend the capacity of the SDA modules and reagent slurry atomizers to treat higher flue gas flows in single spray chambers. Expansion of beneficial byproduct use applications is another ongoing development need.

H_2SO_4 Emission Control

The catalyst used in the selective catalytic reduction (SCR) technology for nitrogen oxides control oxidizes a small fraction of sulfur dioxide in the flue gas to SO_3. The extent of this oxidation depends on the catalyst formulation and SCR operating conditions. Gas-phase SO_3 and sulfuric acid, upon being quenched in plant equipment (e.g., air preheater and wet scrubber), turn into fine acidic mist, which can cause increased plume opacity and undesirable emissions.

An SDA followed by fabric filter provides for high-efficiency H_2SO_4 emissions control (+95% typically). H_2SO_4 removal in wet scrubbers typically falls in the range of 30 to 60%; however, removal efficiencies as low as 15% and as high as 75% have been achieved. R&D efforts are under way to gain a better understanding of the parameters for H_2SO_4 removal in wet scrubbers.

There are a number of emerging technologies that involve injection of dry reagent or slurry containing reagents into the gas path from the economizer inlet to the inlet of the wet scrubber. Reagent is typically injected in two or more locations. Typical reagents are sodium- or magnesium-based. Testing indicates that the acid removal increases when using slurry vs. using dry reagent feed. Some users report nearly 90% reduction of SO_3/H_2SO_4. The technology is not developed to the point where it is commercially bid and backed by performance guarantees.

Performance: WFGD

Wet scrubbers can easily achieve 98% to over 99% SO_2 removal efficiency on any type of coal.

Direction of Technology Development: H_2SO_4 Emission Control

A variety of technologies are now being investigated to control SO_3 and H_2SO_4 cost effectively. Reagent injection for control of SO_3 and H_2SO_4 emissions is an area in which significant R&D efforts are under way. Work is being done to develop a better understanding of H_2SO_4 removal in the wet scrubber.

Particulate Control

Particulate Overview

All coals contain ash, and during the combustion process various forms of particulate, including vaporous products, are formed. The solid particulate is removed from the flue gas using either electrostatic precipitators or high-efficiency fabric filters. Many of the vaporous products can be removed by pretreatment methods that convert the vaporous products into solid particulate upstream of the particulate control. Mercury, for example, is removed using this pretreatment method by the addition of activated carbon.

Electrostatic Precipitators

Overview

Wet and dry electrostatic precipitators (ESPs) are effective devices for the removal of solid or condensed particulate matter and are proven, reliable subsystems for the utility customer.

In an ESP, particulate-laden flue gas enters the ESP, where electrons discharged by the discharge electrode system electrostatically charge the particulate. The charged particles are attracted to the positive grounded collecting surfaces of the ESP. The main difference in the wet ESP and the dry ESP is the method of removing the trapped particle out of the system for disposal. In the dry ESP, the trapped particle is dislodged by mechanical rapping and drops in the ESP hoppers and is removed by using an ash removal system. In a wet ESP, the trapped particle is water-washed, and then the wash water and particulate is routed to the WFGD system and neutralized.

Performance: Wet ESP

The current particulate issue of interest is limiting fine particulate emission (under 2.5 microns) from coal-fired utility stacks. Plants that burn medium- to high-sulfur coals will be adding wet flue gas desulfurization systems on units with existing selective catalytic reduction systems. This will add to the particulate issue, as the mist formed in the scrubber contributes both to fine particulate emissions and stack appearance. Several plants have already experienced visible plumes from these emissions. Fine particulate emissions are also perceived as a health issue. Other hazardous air pollutants may become regulated, and the removal of these pollutants will become a major issue. Wet electrostatic precipitators (wet ESPs) are now being proposed on new boiler projects burning medium- to high-sulfur fuels to mitigate poor stack appearance, to limit acid mist emissions, and to limit fine particulate emissions.

Wet ESPs have successfully served industrial processes for almost 100 years. Cumulative experience gained over the past century is being employed to lower all particulate emissions from modern utility boilers.

As the wet ESP is designed to capture submicron particles, it can be designed to achieve 90 to 95% reduction in PM2.5 (particulate matter). The wet ESP has an added benefit of removing the same or a slightly higher percentage of other fine particulates. It is an excellent polishing device for collection of both solid PM2.5 and condensed particulate formed in the wet FGD system. The wet ESP is also an excellent collector of any remaining PM10 particulate.

Direction of Technology Development: Wet ESP

Wet ESP performance based on requirements for the near future is not an issue. Wet ESP technology development will be cost-centered. Savings on capital investment may be realized by minimizing use of expensive alloys (since alloy costs are unpredictable in today's market) and novel arrangements. Parasitic power may be minimized by additional efforts to mitigate space charge either by redesign or alternate arrangements, and processes could substantially reduce unit size and cost on today's projects.

Performance: Dry ESP

Dry electrostatic precipitators (dry ESPs) have been the workhorse of the utility industry for removal of solid particulate since the 1950s. Dry ESP development came from utility customer requirements to reduce emissions on existing installations, while keeping capital costs at a minimum. The dry ESP is an excellent device for removal of PM10 particulate from the boiler flue gases. It is a relatively good device for removal of solid PM2.5 particulate on some coals.

Future employment of this technology on retrofit projects will depend on utilities evaluation of capital cost versus operating costs of competing technologies. However, new testing methodologies need to be developed to attain repeatable results for the emission levels being required in today's air permits.

Direction of Technology Development: Dry ESP

Today, the technology has evolved by work related to performance enhancements such as wider plate spacing, better discharge electrodes, digital controls and newly developed power supplies. Integration of ESPs with other technologies such as the particle agglomerator is also under consideration. Studies of the effects of unburned carbon on removal efficiency are under way to help this technology perform at its maximum level. The evolution of key dry ESP components such as collecting electrodes, discharge electrodes, wider plate spacing and more effective rapping systems has also improved the reliability of this technology. New technologies or improved technologies such as agglomerators and new power supplies could further enhance dry ESP performance. These enhancements appear to be more cost-competitive than replacement with a new particulate collector. On new projects, careful evaluation of the complete air quality system requirements will be necessary when selecting the primary particulate collector.

Fabric Filters

Technical Description

Fabric filters are particulate collectors that treat combustion flue gas by directing the gas through the filter media. The fabric filter is installed after the air heater as a particulate removal device. The fabric filter may be installed after a dry scrubber or pretreatment device and serves as a multi-pollutant removal device. Solid particulate is captured on the surface of the filter media. The collected particulate is dislodged from the filter media during the cleaning cycle. The dislodged particulate drops into the fabric filter hoppers for removal using the ash removal system. Some applications reuse the collected particulate as a recycled product to enhance the dry scrubber lime utilization.

The U.S. utility industry is favoring pulsejet technology today over reverse gas fabric filters in most coal-fired applications. Worldwide pulsejet has been the preferred fabric filter technology for more than a decade. Advancements in fabric filter cleaning capabilities have resulted in smaller fabric filters that are being used in new and retrofit applications. In fact, there is a growing trend in the industry to convert the older undersized precipitators into high-efficiency fabric filters.

Performance

Fabric filters are the particulate collector of choice for most coal-fired applications. On low-sulfur coals, the fabric filter is coupled with dry scrubber technology and serves as a multi-pollutant control device. On medium- to high-sulfur applications fabric filters are being applied on new units as the primary particulate control device. Only on medium- to high-sulfur coals is the fabric filter less cost-effective than an electrostatic precipitator. Many utilities are choosing the fabric filter over the electrostatic precipitators to ensure fuel flexibility and to keep down mercury-removal costs. The fabric filter is an excellent collector for both PM10 and PM2.5 filterable particulate relative to comparably sized precipitators.

Direction of Technology Development

The power industry is moving from the electrostatic precipitator particulate collector to fabric filter collectors for the majority of new installations. Air quality monitoring and opacity concerns are becoming a public issue, and the industry is responding to these issues with high-efficiency fabric filters.

This shift from precipitators to fabric filters has created a new research focus in the industry for advancements of filter media. Filter media development concentrates on restructuring, blending and coating of existing materials. Membrane-coated filter media are being developed by suppliers worldwide. Specialty filters supplied in cartridge form are commercially available, but much more development is needed. Alternative materials are being developed to improve temperature resistance and increase efficiency. Advancements in cleaning techniques are allowing for more efficient use of filter media including longer bags, which translates into fewer plan area requirements. Electrically enhanced pretreatment of filter media is one of the many advances under development.

Mercury Control

Mercury Overview

Current studies of mercury deposition in the United States indicate that 70% comes from natural sources and non-U.S. manmade emissions. Those non-U.S. anthropogenic emissions originate primarily from China and the rest of Asia. Before March 2005, coal-fired power plants were the largest unregulated anthropogenic source of domestic mercury emissions. However, they still account for less than 1% of global mercury emissions.

In 2005, the Environmental Protection Agency (EPA) proposed to reduce emissions of mercury from U.S. plants through the Clean Air Mercury Rule (CAMR), a two-phase cap-and-trade program. This program is integrated closely with other recent regulations requiring stricter sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emission reductions called Clean Air Interstate Rule (CAIR). The CAMR establishes a nationwide cap-and-trade program that will be implemented in two phases and applies to both existing and new plants. The first phase of control begins in 2010 with a 38-ton mercury emissions cap based on "co-benefit" reductions achieved through stricter SO_2 and NO_X removals. The second phase of control requires a 15-ton mercury emissions cap beginning in 2018. It has been estimated that U.S. coal-fired power plants currently emit approximately 48 tons of mercury per year. As a result, the CAMR requires an overall average reduction in mercury emissions of approximately 69% to meet the Phase II emissions cap.

In the following discussion, the term "co-benefit capture" is defined as utilizing existing environmental equipment, or equipment to be installed for future non-mercury regulation, to capture mercury. The term "active capture" is defined as installation of new equipment for the express purpose of capturing mercury.

Co-Benefit Mercury Control

Due to the large capital investments required of CAIR plants, it makes sense to take full advantage of co-benefit mercury control. Previous testing has demonstrated that various degrees of mercury co-benefit control are achieved by existing conventional air pollution control devices (APCD) installed for removing NO_X, SO_2 and particulate matter (PM) from coal-fired power plant combustion flue gas. The capture of mercury across existing APCDs can vary significantly based on coal properties, flyash properties (including unburned carbon), specific APCD configurations, and other factors, with the level of control ranging from 0% to more than 90%. The most favorable conditions occur in plants firing bituminous coal, with installed selective catalytic reduction (SCR) and wet flue gas desulfurization (WFGD), which may capture as much as 80% with no additional operations and maintenance (O&M) cost. Further R&D investments will be required to fully understand, and be able to accurately predict, co-benefit capture of mercury.

Other co-benefit mercury control technologies are being tested to enhance mercury capture for plants equipped with wet FGD systems. These FGD-related technologies include: 1) coal and flue gas chemical additives and fixed-bed catalysts to increase levels of oxidized mercury in the combustion flue gas; and 2) wet FGD chemical additives to promote mercury capture and prevent re-emission of previously captured mercury from the FGD absorber vessel. The DOE is funding additional research on all of these promising mercury control technologies so that coal-fired power plant operators eventually have a suite of control options available in order to cost effectively comply with the CAMR.

Active Capture Mercury Control

To date, use of activated carbon injection (ACI) has been the most effective near-term mercury control technology. Normally, powdered activated carbon (PAC) is injected directly upstream of the particulate control device (either an ESP or FF) which then captures the adsorbed mercury/PAC and other particulates from the combustion flue gas. Short-term field testing of ACI has been relatively successful, but additional longer-term results will be required before it can be considered to be a commercial technology for coal-fired power plants. There are issues such as the erosion/corrosion effect of long-term use of PAC (or any other injected sorbent or additive) as well as an increase in carbon content for plants that sell their fly ash or gypsum that might adversely affect its sale and lead to increased disposal costs.

Field testing has begun on a number of promising approaches to enhance ACI mercury capture performance for low-rank coal applications, including: 1) the use of chemically treated PACs that compensate for low chlorine concentrations in the combustion flue gas, and 2) coal and flue gas chemical additives that promote mercury oxidation. In order to secure the long-range operability of the existing power generation fleet, it is necessary to continue development of these advanced technologies.

Coal Combustion Products

The production of concrete and cement-like building materials is among the many beneficial reuses of coal combustion products. The use of Coal Combustion Products (CCPs) provides a direct economic benefit to the United States of more than $2.2 billion annually and a total economic value of nearly $4.5 billion each year. These findings are from a recent study published by the American Coal Council (ACC) and authored by Andy Stewart (Power Products Engineering). "The Value of CCPs: An Economic Assessment of CCP Utilization for the U.S. Economy," details the economic value of CCPs, including:

- avoided cost of disposal
- direct income to utilities
- offsets to raw material production
- revenues to marketing companies
- transportation income
- support industries
- research
- federal and state tax revenues

CCPs, created when coal is burned in the generation of electricity, are the third-largest mineral resource produced in the United States.

Annual CCP Production

CCP	2001	2002	2003
Fly Ash	76,013,930	68,869,740	77,239,710
Bottom Ash	21,846,100	22,107,060	26,658,240
FGD Sludge	16,686,700	17,045,140	14,311,500
Gypsum	9,326,100	9,550,700	8,599,400
Other	1,164,900	957,000	1,986,780
TOTAL	**125,037,730**	**118,529,640**	**128,795,630**

Figure 1.8 Source: Federal Energy Regulatory Commission (FERC), EIA Form 767

In 2003, more than 128 million tons (mt) of CCPs were produced in the United States, predominantly fly ash, which accounted for nearly 60% of CCP production. Of the 128 mt of CCPs produced in 2003, 34 mt were utilized in value-added applications, such as cement and concrete products, highway pavement, soil stabilization and construction bedding, manufactured products and agriculture, among others. The production of CCPs has consistently outpaced utilization for the past 35 years, representing significant untapped market potential.

Future Economic Opportunity

The 94 mt of CCPs that were not utilized in 2003 were disposed of or deposited in landfills—a costly and inefficient use of land. According to the ACC study, in 2003 industry spent more than $560 million to dispose of CCPs. The cost savings of beneficial reuse—in other words, the avoided cost of disposal—totaled nearly $200 million in 2003. In addition to providing significant cost savings over landfill deposits, beneficial reuse programs produce better, more durable products and help lower the cost of electricity. This, in turn, leads to greater economic growth and prosperity, which enhances our nation's ability to steward the environment.

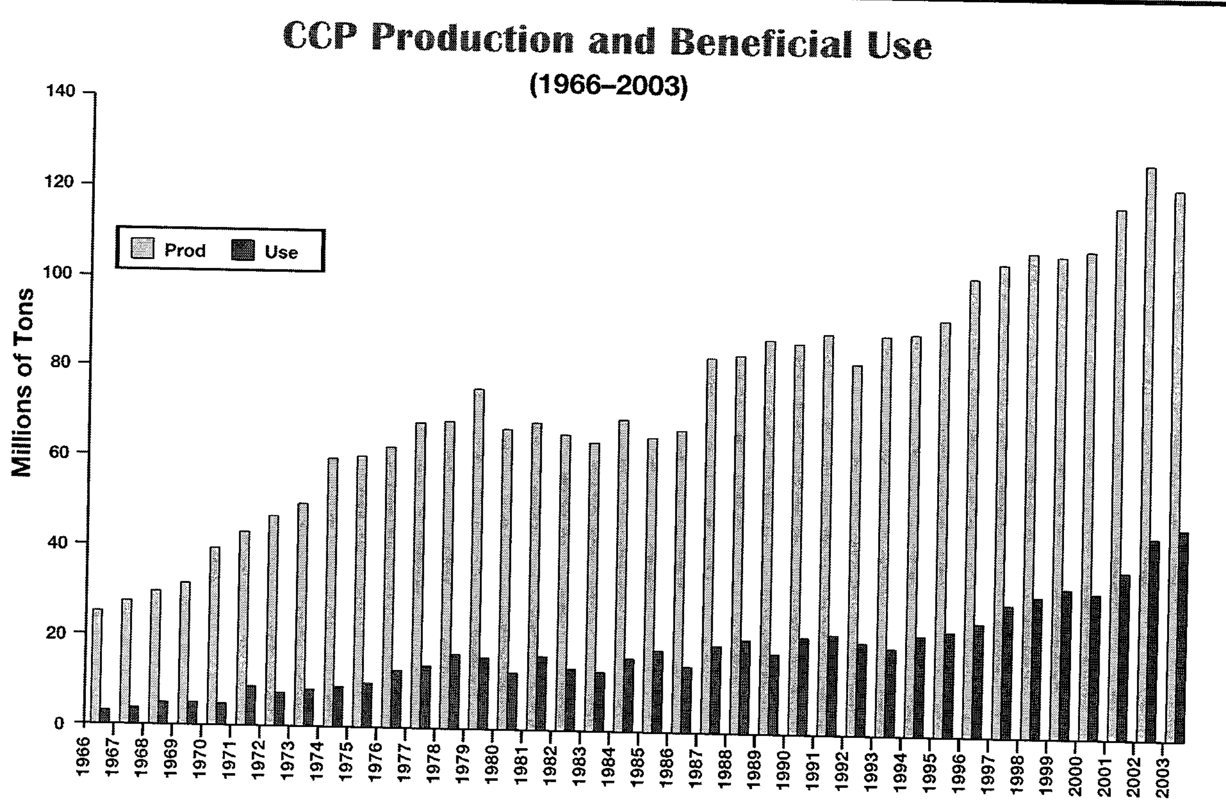

Figure 1.9 Source: American Coal Ash Association Annual Coal Combustion Product Production and Use Survey

Integrated Gasification Combined Cycle (IGCC)

Gasification of coal is a process that occurs when coal is reacted with an oxidizer to produce a fuel-rich product. Principal reactants are coal, oxygen, steam, carbon dioxide and hydrogen, while desired products are usually carbon monoxide, hydrogen and methane.

In its simplest form, coal is gasified with either oxygen or air. The resulting synthesis gas, or syngas, consisting primarily of hydrogen and carbon monoxide, is cooled, cleaned and fired in a gas turbine. The hot exhaust from the gas turbine passes through a heat recovery steam generator where it produces steam that drives a steam turbine. Power is produced from both the gas and steam turbine-generators. By removing the emission-forming constituents from the syngas under pressure prior to combustion in the power block, an IGCC power plant can meet stringent emission standards.

There are many variations on this basic IGCC framework, especially in the degree of integration. The general consensus among IGCC plant designers is that the preferred design is one in which the air separation unit derives part of its air supply from the gas turbine compressor and a part from a separate air compressor. Since prior studies have generally concluded that 25 to 50% air integration is an optimum range, the case study in this section has been developed on that basis.

Three major types of gasification systems are used today: moving bed, fluidized bed and entrained flow. Pressurized gasification is preferred to avoid large auxiliary power losses for compression of the syngas. Most gasification processes currently in use or planned for IGCC applications are oxygen-blown instead of air-blown technology. This results in the production of a higher heating value syngas. In addition, since the nitrogen has been removed from the gas stream in an oxygen-blown gasifier, a lower volume of syngas is produced, which results in a reduction in the size of the equipment. High-pressure, oxygen-blown gasification also provides advantages when CO_2 capture is considered.

Only oxygen-blown gasification has been successfully demonstrated for IGCC. Oxygen-blown gasification avoids the large gas (nitrogen) flows and very large downstream equipment sizes and costs that air-blown gasification would otherwise impose. However, the tradeoff is that an expensive cryogenic oxygen plant is required. Pressurized oxygen-blown gasification reduces equipment sizes and enables the delivery of syngas at the specified fuel pressure required by cooling towers (CTs). Commercially, gasification pressures in IGCC range from about 400 psi to 1,000 psi depending on the process. Current entrained-flow gasification reactors have capacities of about 2000 to 2500 standard tons per day (st/d) of good quality coal. Larger coal sizes are required as coal quality decreases. While somewhat larger gasifier capacities may be possible, two gasifiers might be required for a very low-quality coal to match the syngas energy output of a single gasifier with a high-quality coal.

The gasification process also includes downstream cooling of the raw syngas in a waste heat boiler or by a water quench step. Saturated steam generated in the waste heat boiler is routed to the heat recovery steam generator of the combined cycle where it is superheated and used to augment steam turbine power generation. The steam required for gasification is also supplied from the steam circuit. Cyclones and/or ceramic, sintered metal hot filter and water scrubbing are employed for particulates removal. Water scrubbing also removes ammonia (NH_3), hydrogen cyanide (HCN) and hydrogen chloride (HCl) from the syngas. Following cooling and particulates removal, the sulfur constituents of the syngas are removed in a gas treating plant.

The overall IGCC plant efficiency is also partly determined by the gasification process and configuration selected (heat recovery and quench). The recovery of heat from the hot raw syngas in a waste heat boiler enables a higher efficiency than water quenching of the raw syngas. However, syngas cooling adds significantly to the capital cost of gasification. Syngas heat recovery is an option for all of the gasification processes.

The predominant and preferred gasification processes for good quality solid feedstocks are Shell, General Electric (GE) and ConocoPhillips. Gas entrained-flow processes, as they operate at high temperatures, achieve good carbon conversion and enable higher mass throughputs than other processes. Some entrained-flow gasification processes are also suitable for low-rank fuels, such as lignites.

Entrained-flow gasifiers that operate in the higher-temperature slagging regions have been selected for the majority of IGCC project applications. These include the coal/water-slurry–fed processes of GE. A major advantage of the high-temperature entrained-flow gasifiers is that they avoid tar formation and its related problems. The high reaction rate also allows single gasifiers to be built with large gas outputs sufficient to fuel large commercial gas turbines. Recent studies have shown that a spare gasifier can significantly improve the availability of an IGCC plant.

Coal for Gasifiers

Oxygen-blown gasifiers typically operate better with bituminous and lower volatile coal. In most gasification systems, sulfur content of the coal is only a design consideration for the sulfur-removal system and not an operating limitation on the gasifier.

The composition of coal and some of its physical properties have important influences on the gasification process. Young coals such as lignite and sub-bituminous coal generally contain a high percentage of moisture and oxygen, while old coal, such as bituminous coals and anthracite, tend to become sticky as they are heated. As a result, in the entrained flow gasifier the coal must be dried, because if the water enters the gasifier, some of it will react with CO to form hydrogen and CO_2. Moisture content has no effect on the gasification process in the fixed bed gasifier because the hot gas leaving the gasifier dries the coal as it enters the gasifier.

Since oxygen is present in the gasification process, coals containing more oxygen will need less oxygen or air to be added. For example, an E-gas gasifier system requires 2,220 tons per day of oxygen for sub-bituminous coal, 2,330 tons per day of oxygen for bituminous coal, and 2,540 tons per day for pet coke. The oxygen in coals is particularly important in air-blown gasification as any oxygen in the coal will reduce the amount of air required for the gasification reaction and thereby reduce the resulting nitrogen in the syngas.

Mercury Control with Gasification

Mercury control from coal gasification is applied to the syngas before it is burned, resulting in a significant volumetric reduction from handling flue gas.

For entrained flow systems, essentially all of the mercury in the coal will be present in the syngas. Since syngas volume is considerably less than flue gas, mercury removal systems greater than 90% can be relatively easily applied to the syngas stream.

IGCC OPERATIONS

Owner	Location	Gasification Technology	Syngas Output (MWth)*	Online Year	Feedstock	Products
Sasol-II	South Africa	Lurgi Dry Ash	4,130	1977	Subbit. coal	FT liquids
Sasol-III	South Africa	Lurgi Dry Ash	4,130	1982	Subbit. coal	FT liquids
Repsol/Iberdrola	Spain	GE Energy	1,654	2004a	Vac. residue	Electricity
Dakota Gasification Co.	U.S.	Lurgi Dry Ash	1,545	1984	Lignite res & ref	Syngas
SARLUX srl	Italy	GE Energy	1,067	2000b	Visbreaker res	Electricity & H_2
Shell MDS	Malaysia	Shell	1,032	1993	Natural gas	Mid-distallates
Linde AG	Germany	Shell	984	1997	Visbreaker res	H_2 & methanol
ISAB Energy	Italy	GE Energy	982	1999b	Asphalt	Electricity & H_2
Sasol-I	South Africa	Lurgi Dry Ash	911	1955	Subbit coal	FT liquids
Total France/ edf / GE Energy	France	GE Energy	895	2003a	Fuel oil	Electricity & H_2
Shell Nederland	Netherlands	Shell	637	1997	Visbreaker res	H_2 & electricity
SUV/EGT	Czech Republic	Lurgi Dry Ash	636	1996	Coal	Elec. & steam
Chinese Pet Corp	Taiwan	GE Energy	621	1984	Bitumen	H_2 & CO
Hydro Agri Brunsbuttel	Germany	Shell	615	1978	Hvy Vac res	Ammonia
Global Energy	U.S.	E-gas	591	1995	Bit. coal/ pet coke	Electricity
VEBA Chemie AG	Germany	Shell	588	1973	Vac residue	Ammonia & methanol
Elcogas SA	Spain	PRENFLO	588	1997	Coal & pet coke	Electricity
Motiva Enterprises	U.S.	GE Energy	558	1999b	Fluid pet coke	Electricity
API Raffineria	Italy	GE Energy	496	1999b	Visbreaker res	Electricity
Chemopetrol	Czech Republic	Shell	492	1971	Vac. residue	Methanol & ammonia
NUON	Netherlands	Shell	466	1994	Bit. coal	Electricity
Tampa Electric	U.S.	GE Energy	455	1996	Coal	Electricity
Ultrafertil	Brazil	Shell	451	1979	Asphalt res	Ammonia
Shanghai Pacific	China	GE Energy	439	1995	Anthracite coal	Methanol & town gas
Exxon USA	U.S.	GE Energy	436	2000b	Pet coke	Electricity & syngas
Shanghai Pacific Chemical Corp	China	IGT U-Gas	410	1994	Bit. coal	Fuel gas & town gas
Gujarat National Fertilizer	India	GE Energy	405	1982	Ref. residue	Ammonia & methanol
Esso Singapore	Singapore	GE Energy	364	2000	Residual oil	Electricity & H_2
Quimigal Adubos	Portugal	Shell	328	1984	Vac residue	Ammonia

Figure 1.10

Integrated Gasification Fuel Cell Systems

Fuel cells make it possible to generate electric power with high-efficiency, environmentally benign conversion of fuel to electric energy. If the fuel cells are fueled on syngas from coal, the United States can achieve energy security by using an indigenous fuel source and producing clean-high-efficiency power. Many countries globally, including the United Kingdom, Italy, Germany and Japan, are promoting the development of high-temperature fuel cells for distributed generation and central power.

Fuel cells are electrochemical devices that convert chemical energy in fuels into electrical energy directly. This technology generates electric power with high thermal efficiency and low environmental impact. Unlike conventional power generation technologies (e.g., boilers and heat engines), fuel cells do not produce heat and mechanical work and are not constrained by thermodynamic limitations. Since there is no combustion in fuel cells, power is produced with minimal pollutants. Operation of fuel cells on syngas from gasified coal is the ultimate goal of the U.S. Department of Energy's Solid State Energy Conversion Alliance (SECA) program. This program extends coal-based solid oxide fuel cell technology for central power stations to produce affordable, efficient, environmentally friendly electricity from coal.

In general fuel cells are capable of processing a variety of fuels. The Department of Energy in August 2005 selected the first two projects under the Department's new Fuel Cell Coal-Based Systems program. The projects will be conducted by General Electric Hybrid Power Generations Systems and Siemens Westinghouse Power Corporation. Each team will develop the fuel cell technology required for central power stations to produce affordable, efficient, environmentally friendly electricity from coal. This coal-based solid oxide fuel cell technology will be applied to large central power generation stations.

Planar SOFC Cell Configuration

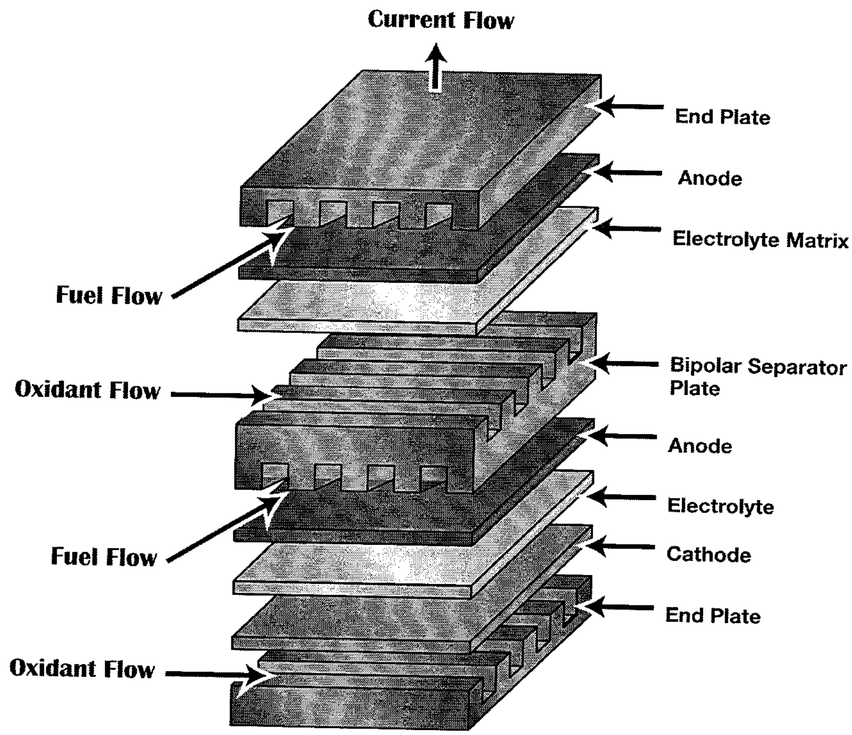

Figure 1.11

The Fuel Cell Coal-Based Systems program is expected to become a key enabling technology for FutureGen. The two teams will demonstrate fuel cell technologies that can support power generation systems larger than 100 MW capacity. Key system requirements to be achieved include:

- 50% plus overall efficiency;
- capturing 90% or more of the carbon dioxide emissions; and
- a cost of $400 per kilowatt, exclusive of the coal gasification unit and carbon dioxide separation subsystems.

Projects will be conducted in three phases. During Phase I, the teams will focus on the design, cost analysis, fabrication and testing of large-scale fuel cell stacks fueled by coal synthesis gas. The Phase I effort is to resolve technical barriers with respect to the manufacture and performance of larger-sized fuel cells. To conduct Phase I, each team is awarded $7.5 million. The duration of Phase I is 36 months.

Phases II and III will focus on the fabrication of aggregate fuel cell systems and will culminate in proof-of-concept systems to be field-tested for a minimum of 25,000 hours. These systems will be sited at existing or planned coal gasification units, potentially at the DOE's FutureGen facility.

SOFC Fuel Cell-Gas Turbine Hybrids

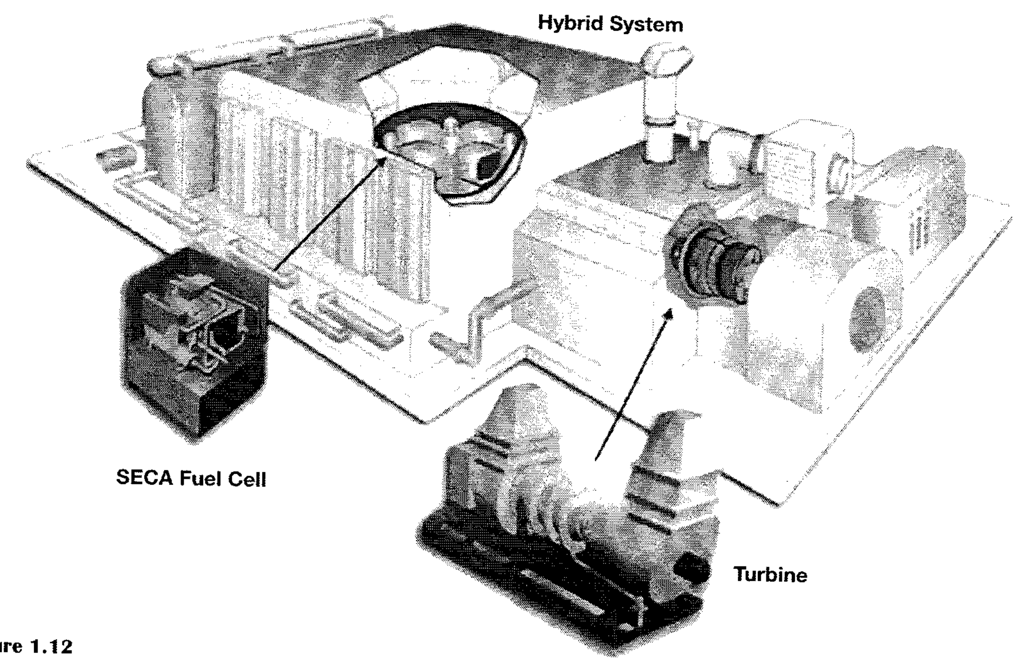

Figure 1.12

Solid Oxide Fuel Cell Coal-Based Power Systems

General Electric Hybrid Power Generation Systems will partner with GE Energy, GE Global Research, the Pacific Northwest National Laboratory and the University of South Carolina to develop an integrated gasification fuel cell system that merges GE's SECA-based solid oxide fuel cell, gas turbine and coal gasification technologies. The system design incorporates a fuel cell/turbine hybrid as the main power generation unit.

Siemens Westinghouse Power Corporation is partnering with ConocoPhillips and Air Products and Chemicals Inc. to develop large-scale fuel cell systems based on their in-house gas turbine and SECA-modified tubular solid oxide fuel cell technology. ConocoPhillips will provide gasifier expertise, while the baseline design will incorporate an ion transport membrane (ITM) oxygen separation unit from Air Products.

CO_2 Overview

Over the last three decades, utilities have implemented emission control equipment to control NO_X, SO_2 and particulate emissions on a large number of coal-fired boilers resulting in significantly improved air quality. Additionally, great progress is being made toward development of low-cost controls for mercury emissions. Public policy dictating reduction of greenhouse gas (GHG) emissions will pose the next major environmental challenge.

Oxyfuel

Of the 325,000 MW of coal-fired power capacity currently in the U.S. generation, which is just over half of the power generated annually, about 90% is provided by pulverized coal combustion. Technologies that can be retrofitted into some of the plants of the existing fleet will have the potential for greater impact on GHG reduction than those requiring construction of new plants. If public policies require GHG emission reductions, oxyfuel combustion is expected to be applicable to the existing pulverized coal plants as well as new pulverized coal plants. For new plants, optimization is anticipated to result in significant improvements in efficiency and reduction in cost.

Technical Description

In a conventional coal-fueled power plant, coal is combusted with air to produce heat and generate steam that is converted to electricity by a turbine-generator. As a result, the flue gas streams are diluted with large quantities of nitrogen from the combustion air. Air contains 78% nitrogen; only the oxygen in the air is used to convert the fuel to heat energy.

In the oxyfuel power plant, combustion air is replaced with relatively pure oxygen. The oxygen is supplied by an on-site air separation unit, with nitrogen and argon being produced as byproducts of the oxygen production. In the oxyfuel plant, a portion of the flue gas is recycled back to the burners and the nitrogen that would normally be conveyed with the air through conventional air-fuel firing is essentially replaced by carbon dioxide by recycling the carbon dioxide. This results in the creation of a flue gas that is a concentrated stream of carbon dioxide and other products of coal combustion, but no nitrogen. This concentrated stream of carbon dioxide is then compressed for transportation and storage in geologic formations.

Advanced processes are also being developed that would reduce the amount of flue gas recycled in an effort to reduce parasitic power. Optimization of the process is also under development, such as integration of the power required by the CO_2 compression train and perhaps the air separation equipment. Process integration has the potential to increase efficiency and reduce cost.

Performance

Current designs suffer considerable degradation in heat rate (i.e., fuel consumption), due to the high power requirement of the cryogenic air separation unit and for compression of the concentrated CO_2 stream to transport for storage. To satisfy these additional parasitic power requirements, the power plant heat rate is estimated to increase to about 12,000 Btu/kWh, resulting in a reduction in net plant efficiency to about 28%. However, potential reductions through development of membrane oxygen separation technologies and increased steam temperature boilers offer potential to decrease heat rate to perhaps 9,800 Btu/kWh HHV (35% net efficiency) or better, which would be about the same as the average coal-fired fleet efficiency in the U.S. today.

Cost

The production of a concentrated stream of CO_2 is a key to enabling storage from fossil power plants. Many technologies are being investigated to facilitate the production of a concentrated CO_2 stream from coal-fired power plants including advanced amine flue gas scrubbing, and oxyfuel combustion. The quality and quantity of economic analyses for these technologies is quite limited. All capture technologies are significantly more costly than conventional pulverized coal combustion and no clear economic winner has yet emerged. Of the options, amine scrubbing and oxygen combustion also provide the opportunity for retrofit onto the existing fleet as well as for new green-field or brown-field plants.

In an oxyfuel plant, the impact on the boiler island is minimal. In fact, as the quantity of flue gas recycled is reduced, the boiler island cost reduces as well. By far, the largest costs are in the air separation unit and CO_2 cleaning and compression train.

Direction of Technology Development

Several engineering studies of both retrofit and new oxyfuel designs have been made and limited pilot scale testing has been completed. Many major equipment manufacturers have completed a significant amount of pilot testing. The next logical step is a small-scale demonstration under utility conditions. Such a demonstration would aid in identifying technology areas for further development and reveal the means of integration and opportunities for significant cost reduction.

Several studies are still needed. These include: plant optimization incorporating an ultra-supercritical boiler, reduction of the quantity of recycle gas, integration of the power requirements for the compression train and lower cost, lower power oxygen production methods.

Proposed Solution Pathways

Reducing or offsetting CO_2 emissions from fossil fuel use is the primary purpose of the new suite of technologies called carbon dioxide capture and storage (CCS). Carbon dioxide can be captured directly from the industrial source, then concentrated into a nearly pure form and stored in geological formations far below the ground surface. Carbon dioxide capture and storage is a four-step process. After the CO_2 is separated from the flue gas, it is compressed to about 100 bars, where it is in a liquid phase. Next, it is put into a pipeline and transported to the location where it is to be stored. Pipelines transporting CO_2 for hundreds of kilometers exist today. The last step is to inject it into the medium in which it will be stored.

CO_2 can be injected into deep underground formations such as depleted oil and gas reservoirs, brine-filled formations or deep unmineable coal beds. This option is in practice today at three industrial scale projects and many smaller pilot tests. At appropriately selected storage sites, retention rates are expected to be very high, with CO_2 remaining securely stored for geologic time periods that will be sufficient for managing emissions from combustion of fossil fuels. The potential storage capacity in geological formations is somewhat uncertain, but estimates of worldwide storage capacity in oil and gas fields range from 900 to 1,200 billion tonnes of CO_2 and the estimated capacity in brine-filled formations is expected to be much greater. The U.S. is estimated to have a very large capacity to store CO_2 in oil fields, gas fields and saline formations, sufficient for the foreseeable future.

Three industrial-scale CCS projects are operating today. Two of them are associated with natural gas production. Natural gas containing greater than several percent CO_2 must be "cleaned up" to pipeline and purchase agreement specifications. The first of these projects, the Sleipner Saline Aquifer Storage Project, began nearly 10 years ago. Annually, 1 million tonnes of CO_2 are separated from natural gas and stored in a deep sub-sea brine-filled sandstone formation. The In Salah Gas Project in Algeria began in 2004 and is storing 1 million tonnes of CO_2 annually in the flanks of a depleting gas field. The third industrial-scale CCS project, located in Saskatchewan, Canada, uses CO_2 from the Dakota Gasification Plant in North Dakota to simultaneously enhance oil production and store CO_2 in the Weyburn Canadian Oil Field. Depending on the generation technology, 1,000 MW coal-fired power plants may emit from 6 million tonnes to 10 million tonnes/year of CO_2. These are a greater volume than the existing capture and storage projects, but experience suggests that capture and storage of this magnitude should be possible.

Cost of CO_2 Capture and Storage Is a Significant Barrier to Deployment

Estimated additional costs for generating electricity from a coal-fired power plant with CCS range from $20 to $70/tonne of CO_2 avoided, depending mainly on the capture technology and concentration of CO_2 in the stream from which it is captured. While this metric may be useful for comparing the cost of CCS with other methods of reducing CO_2 emissions, the increase in costs of electrical generation may be a more meaningful metric. Costs would increase from $0.02/kWh to $0.05/kWh, depending on the generation technology and baseline.

Capture and compression typically account for over 75% of the costs of CCS, with the remaining costs attributed to transportation and underground storage. Pipeline transportation costs are highly site-specific, depending strongly upon economy of scale and pipeline length.

In addition to the high cost of CCS, the loss of efficiency associated with capture and compression is high. The post-combustion, "end-of-pipe" capture technologies use up to 30% of the total energy produced, thus dramatically decreasing the overall efficiency of the power plant. Oxy-combustion has a similarly high energy penalty, although eventually, new materials may lower the energy penalty by allowing for higher temperature and consequently more efficient combustion. Pre-combustion technologies are estimated to require from 10 to 15% of energy output, leading to higher overall efficiency and lower capture costs.

Public and privately sponsored research and development programs are aggressively working to lower the costs of CO_2 capture. The U.S. Department of Energy has a cost goal of $10/tonne CO_2. This challenging target is likely to be hard to meet without significant advances in separations technology, including membrane separators and new absorbents. Recent outreach efforts by the Department of Energy and the National Academy of Sciences are tying to engage academic researchers with new ideas in these areas.

At first glance, CO_2 capture and storage in geological formations may appear to be a radical idea that would be difficult and perhaps risky to employ. Closer analysis, however, reveals that many of the component technologies are mature. A great deal of experience with gasification, CO_2 capture and underground injection of gases and liquids provides the foundation for future CCS operations.

No doubt, challenges lie ahead for CCS. The high cost of capture, the large scale on which geological storage may be employed, and adapting our energy infrastructure to accommodate CCS are significant hurdles to overcome. But none of these seem to be insurmountable, and progress continues through continued deployment of industrial-scale projects, research and development, and growing public awareness of this promising option for lowering CO_2 emissions.

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The Honorable Kathleen A. McGinty
Secretary
Pennsylvania Department of Environmental Protection
Testimony - Waste Coal Incentives
Before the Senate Environmental Resources and Energy Committee
September 8, 2004

Chairman White and members of the Committee it is my privilege to be here today to discuss the administration's efforts to reclaim land and mitigate and eliminate the environmental impacts of waste coal piles while making use of this potential energy resource. I would especially like to thank Senator Stout for holding this timely hearing in his district and calling specific attention to this very important matter and opportunity.

Pennsylvania is a remarkable state with abundant natural riches, including a tremendous heritage of coal production that fueled the industrial revolution and provided hardworking residents with opportunities for a better life. Unfortunately, that legacy also left significant parts of our state scarred from past mining activities.

Travel the back roads of our Commonwealth and it's not uncommon to see refuse piles of unused coal and rock. These waste coal mixtures, commonly called gob or boney piles in the western half of Pennsylvania and culm in the eastern coal fields, are a significant problem in Pennsylvania, which has some 220,000 acres of abandoned mine lands and more than 2,200 miles of streams impaired by polluted mine drainage.

Western Pennsylvania in particular has a significant and proud coal-mining heritage, but as we will hear today from members of this Committee, other speakers and our tour of the Champion waste coal site, this part of Pennsylvania has been especially impacted by the legacy of waste coal disposal. As I will discuss further below, we look at this legacy not as a liability to be mitigated but as an opportunity to be exploited and I will outline proposals that we are developing to take advantage of this unique Pennsylvania resource.

While Pennsylvania's coal economy has indeed contributed greatly to the economic expansion of this country and its success in two world wars, it has left behind numerous scars across the landscape. According to DEP estimates, as of Dec. 2003, there were an estimated 8,529 acres of unreclaimed coal refuse piles throughout Pennsylvania. These piles include at least 258 million tons of waste coal that cause polluted mine drainage, scar the landscape and, in some cases, result in coal refuse fires which contribute to air pollution. Coal refuse piles are also used regularly as dumping piles for trash and other waste. Just one example of the magnitude of these sites is the coal refuse pile that we are going to tour, the Champion site, which, at 500 acres, is the biggest coal refuse pile east of the Mississippi River.

As you know, the department has initiated numerous programs to address the environmental impacts caused by waste coal. One of the most successful programs is the remining program, where mining companies re-mine, or remove the culm banks, screen the material, and transport the suitable refuse material to fuel nearby power generation plants. This removes much of the pyritic material left behind by past coal mining activity that contributes to acid mine drainage, one of the leading causes of stream degradation in the Commonwealth.

When the refuse is burned in the plant, alkaline material is commonly added, and the resulting coal ash -- high in alkalinity -- is then returned to the refuse sites to help reclaim those areas. This prevents any leftover pyritic material from causing acid mine drainage. The removal of the refuse piles can also result in cleaner air due to the elimination of dust sources and, in some cases, uncontrolled burning of the piles. Removing the piles also removes unregulated dumping areas, because people often access these piles through construction access roads in order to dump garbage and other waste.

The Commonwealth has analyzed coal ash and coal ash leachate (water run-off from ash) from many different sources of ash, and has determined that coal ash -- when used appropriately -- is safe to use in mine reclamation projects. This is in part due to the fact that when coal ash is placed at a mine site in an appropriate fashion, it is placed above the ground water table to prevent direct contact with water. In addition, coal ash is usually capped with topsoil -- in many cases up to a four-foot layer -- and that topsoil is then re-vegetated and graded with a three-percent slope. This ensures that rainwater will run off of the site before it comes in direct contact with the placed coal ash. Even if water permeated the topsoil, the compaction of the ash would likely prevent the permeation of water through the ash. The capping with topsoil, sloping of the ash and the compaction of the ash also prevents the rainwater from contacting the pyritic material left behind from the mining operation, so acid mine drainage is never formed.

In addition, leachate tests have shown that even when coal ash comes in contact with water, the metals and other constituents found in coal ash tend not to leach out. This is due to the fact that the chemical make-up of the alkaline coal ash binds up the metals and other constituents in the ash. In addition, the alkalinity of the coal ash prevents the development of acid, which would promote leaching (the coal ash is alkaline due to the addition of alkaline material during the combustion process).

The re-use of this material is a prime example of one of the main environmental themes of the Rendell Administration, namely viewing environmentally harmful material as a potential resource that can be re-used rather than remain as a liability. In 2003 alone, DEP issued mining permits which resulted in the removal of nearly a half-million tons of coal refuse in southwestern Pennsylvania.

Of course, government can't pursue the goal of industrial re-use alone. These efforts are a result of the advent of new boiler technology used by power generation plants called "Circulating Fluidized Beds." These plants burn coal refuse and other fuels that have far less "heating value" (BTU's, or British Thermal Units) than the types of boilers used by the large utilities to burn regular coal.

CFB's are also inherently cleaner than pulverized coal-fired boilers. For more than 30 years, the Department has collected company specific information necessary to obtain estimates for all toxic pollutants. This data demonstrates that dioxin levels were approximately four times lower and most metals, with the exception of mercury, were ten times lower per gigawatt hour than pulverized coal-fired generation. Further, CFBs could achieve very high-levels of mercury control, up to 95%, for very low relative costs should mercury standards be set at the federal level. By comparison, mercury controls on pulverized units would achieve lower-levels of control at higher costs.

Similarly, emissions of NOx and SO2 were also lower than pulverized coal-fired boilers. It should be noted that newly built pulverized coal-fired units would be able to achieve similar emissions levels for S02 due to the installation of scrubbers under Best Available Control Technology determinations. Therefore, newly constructed electric generating combusters of either waste coal or coal would emit at comparable levels because both would be employing very similar BACT for all pollutants. We have attached a comparative analysis of waste coal emissions developed by our Bureau of Air Quality, which provides more details on this matter. MS Word PDF

There are 15 plants burning coal mining refuse in CFB's located in Pennsylvania. The first of these plants came on line in Pennsylvania in 1988. According to ARIPPA, a trade organization representing 13 of the CFB plants in the Commonwealth, from 1988 through the end of 2003, coal refuse plants in Pennsylvania consumed 88.5 million tons of coal refuse, mostly from abandoned refuse piles. Approximately 19 million tons of that were burned in coal refuse plants in the southwest region of the Commonwealth. ARIPPA's records show that the plants in the Commonwealth burn an average of about 7.5 million tons of coal refuse per year, mostly from abandoned coal refuse piles.

The coal refuse that fuels these plants is removed -- or remined -- from the refuse piles under the regulation of DEP. Thanks to DEP's remining program, there have been numerous success stories in southwestern Pennsylvania in the effort to reclaim coal refuse piles. One of these examples is the scheduled removal of 60 million tons of coal refuse from over 40 different coal refuse piles in seven counties, including Allegheny, Westmoreland, Indiana, Cambria, Armstrong, Huntingdon and Somerset. These piles are scheduled to be removed and burned in the newly-constructed Reliant Energy plant, a 500-megawatt fluidized bed coal refuse-burning power plant at Seward in East Wheatfield Township, Indiana County. Reliant received $400 million in tax-exempt financing (bonds) from the Pennsylvania Department of Community and Economic Development for this project. It is estimated there is an additional 10-20 million tons to be found in piles that are still on a list to be explored and evaluated for possible use by Reliant.

While the project will result in the elimination of harmful coal refuse piles, it is also contributing to the creation of over 300 much-needed jobs throughout southwestern Pennsylvania. This underlies another major tenet of the Rendell Administration: spurring job creation and economic growth. The ability to create jobs while simultaneously cleaning up environmental scars from the past is a double-win for the Commonwealth. It's also important to note that without industry involvement, this type of success in all probability would not be happening: it's unlikely government would have the resources available to reclaim many of these coal refuse piles.

DEP also issues reclamation contracts to mine operators to reclaim refuse piles, such as the nearly 19-acre Crucible Pile in Greene County that is currently being reclaimed, and has granted funds through the Growing Greener program to various organizations to reclaim waste coal piles. For example, DEP awarded two Growing Greener grants for a total of approximately $4.6 million to the Greene County Industrial Development Authority to reclaim the Mather coal refuse pile in Greene County. That project is still under way and includes the removal of material and the capping of the area with on-site material such as top soil. That project should be completed within a year.

In addition to the environmental and economic benefits derived from the re-use of waste coal, the Commonwealth's 15 waste coal power plants generate enough electricity to power approximately 1 million homes annually. They do this with relatively low air emissions, adding to the environmental success of cleaning up waste coal piles that cause water and air pollution.

According to ARIPPA, since 1988 Pennsylvania's waste coal industry has reclaimed approximately 3,429 acres of abandoned mine lands. The Department estimates the cost of government-sponsored reclamation to be between $20,000 to $40,000 per acre. Consequently, these efforts have saved the taxpayers of this Commonwealth between $68 million and $137 million since1988, an amount equal to approximately three to six years of federal abandoned mine land appropriations to our state.

Even the residual ash from electric generation at these facilities provides a benefit for Pennsylvania as it is used to fill strip mine pits with dangerous highwalls. Similarly, because the ash is mixed with limestone, the alkaline mixture makes it effective for use to remediate the acidic drainage that pollutes streams and threatens drinking water supplies.

Using waste coal to produce energy is an innovative process that will attract new investment and help to create the jobs we critically need while ensuring the highest standards of environmental protection and public health. Pennsylvania exports more than $20 billion a year to import energy fuels--that's nearly as much as our entire state budget. Yet, indigenous energy development has a multiplier effect in the economy that may generate as much as 1.6 times more revenue than from imports. Keeping energy dollars in state clearly is an important step in retaining and generating more jobs in Pennsylvania.

The Rendell administration has recently initiated two actions to help support and promote Pennsylvania's waste coal industry. During his January budget address Governor Rendell announced that the Commonwealth would purchase ten percent of its electricity from clean, advanced energy sources, including waste coal. I am pleased to note that we recently completed this purchase, which includes 10,000 megawatt hours of waste coal -- out of a total of 100,000 megawatt hours of clean, advanced electricity.

In April Governor Rendell reestablished the dormant Pennsylvania Energy Development Authority, PEDA. As many of the members of this Committee know, PEDA was first established to encourage the development of Pennsylvania's energy resources. PEDA possesses $300 million in tax-exempt bonding authority and in the past this capability has been used to finance waste-coal power plants, notably the Ebensburg, Cambria facility. PEDA will work in concert with the Pennsylvania Economic Development Financing Authority, thereby expanding the financing capabilities of the Commonwealth. As you know, PEDFA financing was instrumental in enabling the re-powering of the Seward, Reliant power plant to utilize waste coal.

We are currently in discussions with developers seeking to deploy state-of-the-art advanced coal gasification technology, which in some cases will be able to utilize waste coal as a fuel.

Projects utilizing waste coal are also a focus of the Pennsylvania Energy Harvest Grant Program. This $5 million annual grant program provides funding to projects that improve the environment through advanced energy solutions. Last year, Energy Harvest funded two waste coal projects. The first is a joint project with the U.S. Department of Energy and CO Inc. to demonstrate the utilization of coal fines. The process, termed "Granu Flow," adds asphalt emulsion, or a similar, binder to agglomerate the coal fines. Once these fines are bound together they will be able to be utilized as fuel in waste coal power plants. Energy Harvest also provided funds to the River Hill Power Company Project in Clearfield County for preliminary environmental and fuel quality analysis for their proposed waste coal power plant. Together, Energy Harvest provided nearly $400,000 for these two projects.

In addition to the tools provided by the Commonwealth's electricity purchase PEDA, and Energy Harvest the Governor has also advocated for an Advanced Energy Portfolio Standard that would include waste coal as an eligible resource. I know this Committee has already held several hearings on this subject so I will refrain from covering the basics of portfolio standards and the Governor's proposal in general and, instead, will focus my remarks specifically on the role waste coal can play as an eligible resource.

As you know, many portfolio standards limit eligibility to renewable resources. We do not feel that this is the best approach for Pennsylvania. As I discussed earlier in my testimony, Pennsylvania's unique history and geology mean that we should take a broader view to include other resources, such as fugitive coal-mine methane and waste coal, that while not considered "traditional" renewables, still provide a net environmental benefit to the Commonwealth.

Therefore, the Governor has proposed a two-tiered portfolio standard, an Advanced Energy Portfolio Standard, which includes waste coal as an eligible resource in the second tier. The first tier would be made-up of traditional renewables, energy efficiency, energy conservation, efficiency upgrades at existing power plants, recycled energy and electricity generated from fugitive coal-mine methane. The second tier would include emissions offsets and electricity generated from fuel cells powered by non-renewable fuel, and waste coal.

Because participation in an Advanced Energy Portfolio Standard will provide economic benefits to qualifying facilities, by making power purchase contracts with those facilities more attractive to electric distribution companies and electric generation suppliers and through the sale of advanced energy credits, we believe that the qualifying facilities should be attaining the highest possible environmental standards. As such, we are proposing that qualifying facilities should meet the highest attainable emissions standards for nitrogen oxide, sulfur dioxide, particulates, and volatile organic compounds. By including an emissions standard we will ensure that our unique Pennsylvania energy resources are utilized in a way that protects the health and environmental quality of all the Commonwealth's citizens.

To clarify, this standard would not replace any facilities existing air quality permits. Facilities would still be in compliance so long as they are meeting the standards set in their current operating permits. These standards would be the requirement, essentially a higher bar, which facilities would need to meet in order to qualify for eligibility as part of the Advanced Energy Portfolio Standard.

In order for waste coal to be a meaningful part of the Advanced Energy Portfolio Standard we believe the portfolio standard targets set for the second tier should be sufficient to include both the existing power plants and to provide incentives for some new plants to be built. As was demonstrated in my testimony earlier, Pennsylvania's existing waste coal industry has and continues to provide tremendous environmental and economic benefits to the Commonwealth's citizens. However, because many of the smaller merchant facilities have power purchase agreements that will expire, in many cases, by 2013 we believe there is a need to continue to incentivize their existence and the reclamation work they are doing.

Still, as we will see later today when we visit the Champion refuse pile, there are still many areas of the state that would greatly benefit from reclamation resulting from waste coal utilization that currently have no outlet for existing abandoned waste coal piles. As such, we believe that a portfolio standard that includes waste coal should consider a target that will also incentivize new projects. We can discuss what such a target should be as we move forward in developing legislative drafts, however, for starters we believe that a second tier target of ten percent in ten years makes sense. Pennsylvania's existing and projected waste coal power plants will likely generate enough electricity to meet as much as 8% of the Commonwealth's projected electricity demand ten years from now. Thus, a ten percent overall goal would be keeping in line with the Governor's original proposal for a three percent second tier to incentivize new projects.

We believe in the view that the waste coal many individuals may see as liabilities can truly be an asset if we use our imagination for innovative solutions. The incentives that we are proposing above will provide both the policy framework and the financial tools to turn these opportunities and solutions into a reality. Again, I thank the Committee for the opportunity to present to you today. I would be happy to answer any questions that you have at this time.