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Attorney General

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September 14, 2007

RECEIVED
SEP 17 2007
EPA REGION III
OFFICE OF REGIONAL ADMINISTRATOR

Hon. Stephen L. Johnson, Administrator
United States Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Re: *Petition for Reconsideration of the Final Order of the Environmental Protection Agency, 72 Fed. Reg. 39414 (July 18, 2007)*

Dear Administrator Johnson:

On behalf of the State of New Jersey, Department of Environmental Protection, enclosed for your review please find a Petition for Reconsideration with attachments with respect to the above referenced final agency order.

Sincerely yours,

ANNE MILGRAM
ATTORNEY GENERAL OF NEW JERSEY

By: Kevin P. Auerbacher
Kevin P. Auerbacher
Deputy Attorney General

cc: Donald S. Welsh, Regional Administrator, Region III
Jon M. Lipshultz, United States Department of Justice
Eric Gerig Hostetler, United States Department of Justice

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SEP 18 2007
Division Director (3AP00)

BEFORE THE HONORABLE STEPHEN L. JOHNSON, ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN RE: DENIAL OF NEW JERSEY DEPARTMENT OF ENVIRONMENTAL PROTECTION'S REQUEST THAT THE ADMINISTRATOR OBJECT TO ISSUANCE OF STATE OPERATING PERMIT FOR PORTLAND GENERATING STATION 72 FED. REG. 137 (JULY 18, 2007)

PETITION FOR RECONSIDERATION

Submitted by The New Jersey
Department of Environmental Protection

Pursuant to Section 307(d)(7)(B) of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B), the New Jersey Department of Environmental Protection ("NJDEP") hereby petitions the Administrator of the United States Environmental Protection Agency ("EPA") to reconsider the denial of NJDEP's Title V Petition regarding the Portland Generating Station published on July 18, 2007. See 72 Fed. Reg. 39,414 (July 18, 2007)("Denial"). The permit holder for the Portland Generating Station ("Portland Plant") is currently Reliant Mid-Atlantic Power Holdings LLC ("Reliant"), which is a subsidiary of Reliant Energy, Inc.

The Denial first unlawfully failed to consider the merits of NJDEP's objection to the lack of operational heat input limits in the Title V Permit for the Portland Plant. As discussed below, the removal of enforceable heat input limits from the permit did not arise during the period for public comment on the permit. As such, pursuant to Clean Air Act section 505(b)(2), 42 U.S.C. § 7661d(b)(2), NJDEP properly raised the objection in its Title V Petition dated July 21, 2006, and EPA must reconsider its Denial to address this issue of central relevance to the Portland Plant's permit. The Denial also improperly rejected NJDEP's heat input objections concerning violations of emission standards and limitations–objections that are also centrally relevant here--based upon the monitoring and testing requirements in the permit for Portland.

BACKGROUND

The Pennsylvania Department of Environmental Protection ("PADEP") released for public comment a draft operating permit for the Portland Plant on June 8, 2005. Located in Upper Mount Bethel Township, Northampton County, Pennsylvania, the Portland Plant's emissions contribute to damages to public health and the environment in New Jersey. The Portland Plant was ranked in a recent Environmental Integrity Project Report as number five in the Top 50 Dirtiest Power Plants in the nation for sulfur dioxide ("SO2") emissions, (attached as Exhibit 1), and the plant's sulfate and nitrate particle emissions are of special concern to New Jersey because of their impact on New Jersey's fine particulate nonattainment areas, see 40 C.F.R. § 81.331.

On July 8, 2005, NJDEP submitted timely comments on PADEP's proposed operating permit.[1] In general terms, these comments provided that the proposed permit would allow for violations of the Clean Air Act's ("Act") Prevention of Significant Deterioration ("PSD") provisions, New Source Performance Standards ("NSPS"), and the Pennsylvania regulations at

[1] Because PADEP released identical permits to the public and EPA at the same time in June 2005, EPA submitted comments to PADEP before NJDEP had provided its comments. It does not appear that PADEP forwarded NJDEP's comments to EPA until December 2, 2005.

25 PA Code Chapter 127, Subchapter B.[2]

The proposed permit, which was marked "unofficial," was sent to EPA on or about May 24, 2006 ("Unofficial Permit"). Subsequent to the draft permit, and based on Reliant's request, in the Unofficial Permit, PADEP inserted, for the first time, a footnote which expressly provided that the maximum heat input values set forth in the permit would not be enforceable and were included in the permit only for "informational" purposes. This revision was made subsequent to the close of the comment period (approximately August 4, 2005). See Exhibit 2.

On July 21, 2006, NJDEP filed a Title V Petition with EPA pursuant to Section 505(b)(2) of the Act, petitioning EPA to object to the proposed Title V permit from PADEP for the Portland Plant. The Petition demonstrated that: (1) the permit lists increased heat input values, and these increases, as well as NJDEP's Notice of Intent to Sue, reflect PSD violations that must be addressed in a compliance schedule in the permit[3]; and (2) operational limits based on heat input are necessary elements of the permit in order to ensure that there are no violations of the National Ambient Air Quality Standards ("NAAQS"), including for Nitrogen Dioxide and fine Particulate Matter ("PM-2.5"), the NSPS standards at 42 U.S.C. § 7411, or the Pennsylvania SIP.

Under Title V of the Act, EPA has only sixty (60) days to either deny or grant a Title V Petition. See 42 U.S.C. § 7661d(b)(2). This statutory time line for the July 21, 2006 NJDEP

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[2] On November 16, 2005, NJDEP served Reliant with a Notice of Intent to Sue based on violations of the Act's PSD provisions for the Electrical Generating Units 1 and 2 at Reliant's Portland Plant.

[3] Title V of the Act provides that violations of any "applicable requirements," such as NSPS requirements and the requirement to obtain a preconstruction permit in accordance with the Act, must be addressed in a compliance schedule in the Title V operating permit. 42 U.S.C. § 7661d(c); 40 C.F.R. § 70.5(c)(8)(iii)(c).

Petition expired on or about September 20, 2006. Despite this time requirement, EPA did not respond to the Title V Petition until after NJDEP: (1) on February 6, 2007, filed suit against EPA in the District Court of New Jersey seeking to compel EPA to respond to the Title V Petition; and (2) entered into a Settlement Agreement with EPA whereby EPA agreed to either grant or deny the Title V Petition by June 20, 2007. On June 20, 2007, EPA denied NJDEP's Title V Petition, and the denial was published in the Federal Register on July 18, 2007. 72 Fed. Reg. 39,414. NJDEP subsequently voluntarily dismissed the Complaint against EPA pursuant to the Settlement Agreement with the exception of NJDEP's claim for costs in that matter.

In denying NJDEP's Title V Petition, EPA alleged that NJDEP did not make the requisite "demonstration" of PSD violations that was required before a compliance plan would be imposed in Reliant's Title V permit.[4] With respect to NJDEP's argument that the lack of limitations on the Portland Plant's heat input can lead to NAAQS violations, EPA's Denial was based solely on NJDEP's "failure" to raise in its comments on the draft permit or in its Title V Petition the argument that the lack of heat input limits in the permit would lead to NAAQS exceedances. The Denial further provided that NJDEP presented insufficient evidence to establish that NSPS is an "applicable requirement" to the Portland plant. Finally, EPA stated that there was "no need" for heat input limits to ensure compliance with the Pennsylvania SIP because "the proposed permit provides sufficient monitoring to ensure compliance."

ISSUE FOR RECONSIDERATION

[4] EPA's reasoning here is in direct conflict with the Second Circuit's decision in NY PIRG v. Johnson, 427 F.3d 172, 180 (2d Cir. 2005) which provides, "[i]ssuance of ... NOVs and commencement of suit is a sufficient demonstration to the Administrator of non-compliance for purposes of the Title V permit review process"). NJDEP is appealing this issue in a Petition for Review filed with the D.C. Circuit Court of Appeals.

I. EPA UNLAWFULLY DENIED NJDEP'S OBJECTIONS TO THE PORTLAND PLANT PERMIT REGARDING HEAT INPUT

A. Section 505(b)(2) requires that EPA consider the merits of NJDEP's objection regarding NAAQS violations

Under Title V of the Act, any party may bring a Title V Petition before EPA with respect to permits that are not in compliance with the applicable requirements of the Clean Air Act. 42 U.S.C. § 7661d(b)(2). Under this same provision, "[t]he petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting agency (unless the petitioner demonstrates in the petition to the Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period)" (emphasis added). Thus, the plain language of the Act exhibits two exceptions to the rule that objections to the Title V permit must be raised with reasonable specificity during the public comment period: 1) where the petitioner demonstrates in a petition to EPA that it was impracticable to raise the objection within the comment period; and 2) where the grounds for such objection arose after the public comment period. Notably, only the first exception requires the petitioner to make a demonstration in a Title V Petition.

The relevant objection in this matter falls into the second statutory exception to the typical comment requirement as it arose after the close of the comment period on the draft permit. In its Petition, NJDEP summarized the heat input objection by stating that:

> The permit does not assure that emissions from the Portland plant will not result in exceedances of the National Ambient Air Quality Standards ("NAAQS") for nitrogen oxides ("NOx") and particulate matter ("PM"). Therefore the permit must contain operational limits in the form of heat input limits.

Petition at 3. As the Petition demonstrated, because various Pennsylvania emission limits are based on heat input values, increases in heat input capacity will result in Portland emitting higher hourly emissions. Most egregious, the Unofficial Permit can lead to increases in the pounds per hour emission rates and annual emission rates of PM (and as a result, PM-10 and PM-2.5) for both Units and of NOx for Unit 1. The Unofficial Permit can also lead to increases in the 1-hour pounds per hour emission rates for SO2 and NOx for both Units at the Portland Plant. These emissions increases could impact both Pennsylvania's and New Jersey's attainment of NAAQS for PM-2.5 (and, although not likely, if the heat input increased to a sufficient level, there could also be violations of the NO2 NAAQS for NOx), underscoring the need for operational limits for heat input as independent conditions in the permit. In addition, increases in heat input could lead to increases in hazardous air pollutants, including but not limited to, heavy metal particulate, mercury, acid gases such as hydrochloric acid, and hazardous organic substances.

The proposed Title V Permit for Portland on which NJDEP submitted comment listed the rated heat input limits of Portland's Units 1 and 2 as 1,657.2 and 2,511.6 MMBTU/Hr respectively. See Exhibit 3. These heat rate capacities were included in both the "Facility/Source Identification" section of the permit, as well as the "Site Level Title V Requirements" section, which stated "Source Capacity/Throughput: 1,657.200 MMBTU/HR" (for Unit 1). Moreover, the "General Title V Requirements" section of the permit included as a compliance requirement that:

> A person may not cause or permit the operation of a source, which is subject to 25 Pa. Code Article III, unless the source(s) and air cleaning devices identified in the application for the plan approval and operating permit and the plan approval issued to the source are

> operated and maintained in accordance with specifications in the applications and the conditions in the plan approval and operating permit issued by the Department.

Draft Title V Permit at 8, Exhibit 3.

It was not until the Unofficial Permit that PADEP provided any indication that the heat input capacities would not be considered enforceable limits. Indeed, it was in response to Reliant's request (which was made after the close of the comment period) that PADEP inserted the new footnote in the Unofficial Permit. This footnote provides, contrary to before, that limitations on heat input set forth in the permit are not to be enforced and are included as "informational" only. See Unofficial Permit at 70, Exhibit 2. This change in position triggered NJDEP's ultimate objection, as reflected in its Title V Petition, which specifically requested that "PADEP should delete from the Title V permit language suggested by Reliant, namely, that 'Heat input capacities listed in Section A (Site Inventory) and Section D (Source Level Requirements) are for informational purposes only and are not enforceable limits.'" Petition at 8. Since the footnote language was not included in the permit until May 31, 2006, approximately ten months after the close of the public comment period, NJDEP could not have raised its argument that the lack of enforceable heat input limits in the operating permit would lead to NAAQS exceedances in its public comments.

Since the grounds for NJDEP's objection arose after the public comment period, section 505(b)(2) of the Act mandates that EPA consider the merits of the objection despite its absence from the public comment record. See 42 U.S.C. § 7661d(b)(2). EPA, however, disregarded this statutory requirement in its Denial. The Denial states that "having failed to give the permitting authority a meaningful opportunity to address this issue, the issue will not be considered here."

Denial at 8. This summary dismissal of a validly raised objection constitutes a clear violation of the Act. EPA should reconsider its denial of NJDEP's Petition to remedy this violation.

B. The lack of operational heat input limits in the permit is of central relevance to EPA's Denial

While a Petition for Reconsideration is not required in challenges to EPA's denial of a Title V Petition,[5] NJDEP is filing this Petition for Reconsideration with EPA in order to provide EPA with an opportunity to review NJDEP's heat input arguments.[6] The Act's provisions regarding petitions for reconsideration provide that a reconsideration proceeding is mandated where an "objection is of central relevance to the outcome of a rule." 42 U.S.C. § 7607(d)(7)(B). In this matter, NJDEP raises the centrally relevant questions of Portland's impact on NAAQS and emission standards and limitations, therefore warranting reconsideration by EPA.

All Title V Permits are required to contain "conditions as are necessary to assure

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[5] The Act's provisions for judicial review of rulemaking, see 42 U.S.C. § 7607(d)(7)(B), set forth specific provisions for filing Petitions for Reconsideration. Under this provision, a reviewing court may only consider "an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment, " but the Administrator may convene a proceeding for reconsideration to explore those objections that could not be raised during the comment period. Title V of the Act, See 42 U.S.C. § 7661d(b)(2), in contrast, merely provides a general cross reference to the judicial review provisions of the Act as a whole ("[a]ny denial of such petition shall be subject to judicial review under section 7607 of this title"). This general cross reference in Section 505 guides appeals of denials of Title V Petitions to the appropriate Circuit Court, not to the detailed Petition for Reconsideration provisions which are expressly applicable to rulemaking, see 42 U.S.C. § 7607(d)(7)(B).

[6] NJDEP is filing the Petition for Reconsideration simultaneously with its filing of a Petition for Review of the Denial with the Third Circuit pursuant to 42 U.S.C. § 7607(b)(1) ("any ... final action of the Administrator under this chapter ... which is locally or regionally applicable may be filed only in the United States Court of Appeals for the appropriate circuit").

compliance with applicable requirements of [the Act]." 42 U.S.C. § 7661c(a). With respect to the NAAQS, 40 C.F.R. § 70.2(13) expressly provides that these standards are "applicable requirements." In addition, the NAAQS are a fundamental aspect of the Clean Air Act and are established in order to protect the public health. 42 U.S.C. § 7409(b). The Act accordingly directs each State to implement a plan for the maintenance of the NAAQS that includes enforceable emission limitations and other control measures, means or techniques as necessary to meet the requirements of the Act. 42 U.S.C. § 7410 (a). In addition, Pennsylvania rules provide that a Title V permit application shall "[s]how that the source will not prevent or adversely affect the attainment or maintenance of ambient air quality standards when requested by the Department." 25 Pa. Code 127.12(6). Thus, Portland's Title V Permit is required to contain conditions assuring compliance with the NAAQS.

As NJDEP's Petition notes, the Permit fails to meet this requirement since it would allow for potentially large increases in emissions through increases in the plant's uncontrolled heat input. If EPA had substantively considered NJDEP's objection, it would have considered the potential impact of the plant's emissions on NAAQS for areas around the Portland Plant. In the absence of such consideration by EPA, NJDEP conducted refined modeling of Portland's emissions, attached here as Exhibit 4. Exhibit 4 contains a brief description of the modeling, the data sets used, and the results. Also enclosed with Exhibit 4 is a CD that includes the input and output files. Since the modeling shows existing NAAQS violations at the heat inputs in the Unofficial Permit, any increases in particulate emissions as a result of heat input increases would cause new violations (the area of violations increases) of the 24-hour PM-2.5 NAAQS and exacerbate existing modeled violations of the 24-hour PM-2.5 NAAQS in the vicinity of the

Portland Plant. Exhibit 4 also gives specific details on the area of impact, which includes both New Jersey and Pennsylvania. Moreover, Portland's impact on New Jersey's designated PM-2.5 nonattainment areas to the east would increase in magnitude if heat input levels are increased. Also, of concern is the fact that the modeling shows that the Portland Plant's sulfur dioxide emissions have the potential of causing violations of the 3-hour and 24-hour SO2 NAAQS in the vicinity of the Portland Plant. The synergistic effects of high levels of sulfur dioxide in combination with the high levels of PM-2.5 (both above their respective NAAQS) will have even a greater detrimental effect on public health in the area.

Because EPA did not substantively consider the argument that the lack of enforceable heat input limitations in the Unofficial Permit for the Portland Plant can lead to exceedances of the NAAQS, and based on the modeling performed by NJDEP, EPA should reconsider its denial of this aspect of NJDEP's Title V Petition and find, now, that the Unofficial Permit is objectionable on this ground.

Also "centrally relevant" here is NJDEP's demonstration in the Petition that the Unofficial Permit will lead to violations of applicable emission standards and limitations. Such standards and limitations in the Pennsylvania SIP are also "applicable requirements" that the Title V permit must assure compliance with. See 40 C.F.R. § 70.2(1).

In the Denial, EPA improperly relies upon the monitoring and testing requirements in the Unofficial Permit for the reasoning that "there is no need for additional heat input or operational limits in the title V permit to assure compliance with ... emission standards and limitations." EPA's reasoning is most problematic with respect to PM emissions, as the continuous opacity monitor ("COM"), for at least three reasons, does not limit the mass emission rate of particulate emissions. First, there is no constant correlation of opacity with noncondensible (filterable) particulate emissions that the opacity monitor "sees" in the stack. Variability of coal, combustion conditions, and many other factors would change the correlation over time. Infrequent stack tests only provide a correlation with the noncondensible particulate emissions for the conditions in place at the time of the tests. Second, there is no correlation of opacity with condensible particulate emissions that the opacity monitor does not "see" in the stack. Condensible particulate matter is a gas in the stack, is not detected by the COM, and changes quickly to condensed particulate matter after exiting the stack. Condensible particulate matter is even more sensitive to variability of coal, combustion conditions and other factors.

Third, and most obvious, Pennsylvania has set only a concentration limit on particulate emissions in the Unofficial Permit. Therefore, without a heat input limit, there is no limit on the mass emission rate of particulate emissions. The combination of an enforceable heat input limit (million btu per hour) and concentration limit (pound per million btu) would result in an enforceable mass emission limit (pound per hour). Without the enforceable heat input limit, the pounds per hour particulate emissions would increase at least proportionately to increases in heat input beyond that specified in Title V applications and the draft permit for the Portland Plant. Moreover, the actual increase in particulate emissions would be more than proportional because the efficiency of the particulate control device decreases as the gas flow increases since the heat input increases as more coal is burned. Hence, a 10% increase in heat input over the maximum specified would have a much more than 10% increase in mass emission rate (lb/hr). For these reasons and due to the resulting adverse health impact from increased ground-level particulate concentrations, EPA should also reconsider this aspect of the Denial that is based upon the monitoring and testing requirements in the Unofficial Permit.

Finally, NJDEP requests that EPA review the impact that increases in heat input at the Portland Plant would have on emissions of hazardous air pollutants, including but not limited to heavy metal particulates, mercury, acid gases, and hazardous organic substances.

RELIEF REQUESTED

For all of these reasons, NJDEP respectfully requests that the Administrator convene a proceeding for reconsideration of the Denial.

Dated: 7/14/07

Respectfully submitted,

ANNE MILGRAM,
ATTORNEY GENERAL
STATE OF NEW JERSEY

By: Kevin P. Auerbacher /s/ REL
Kevin P. Auerbacher
Deputy Attorney General

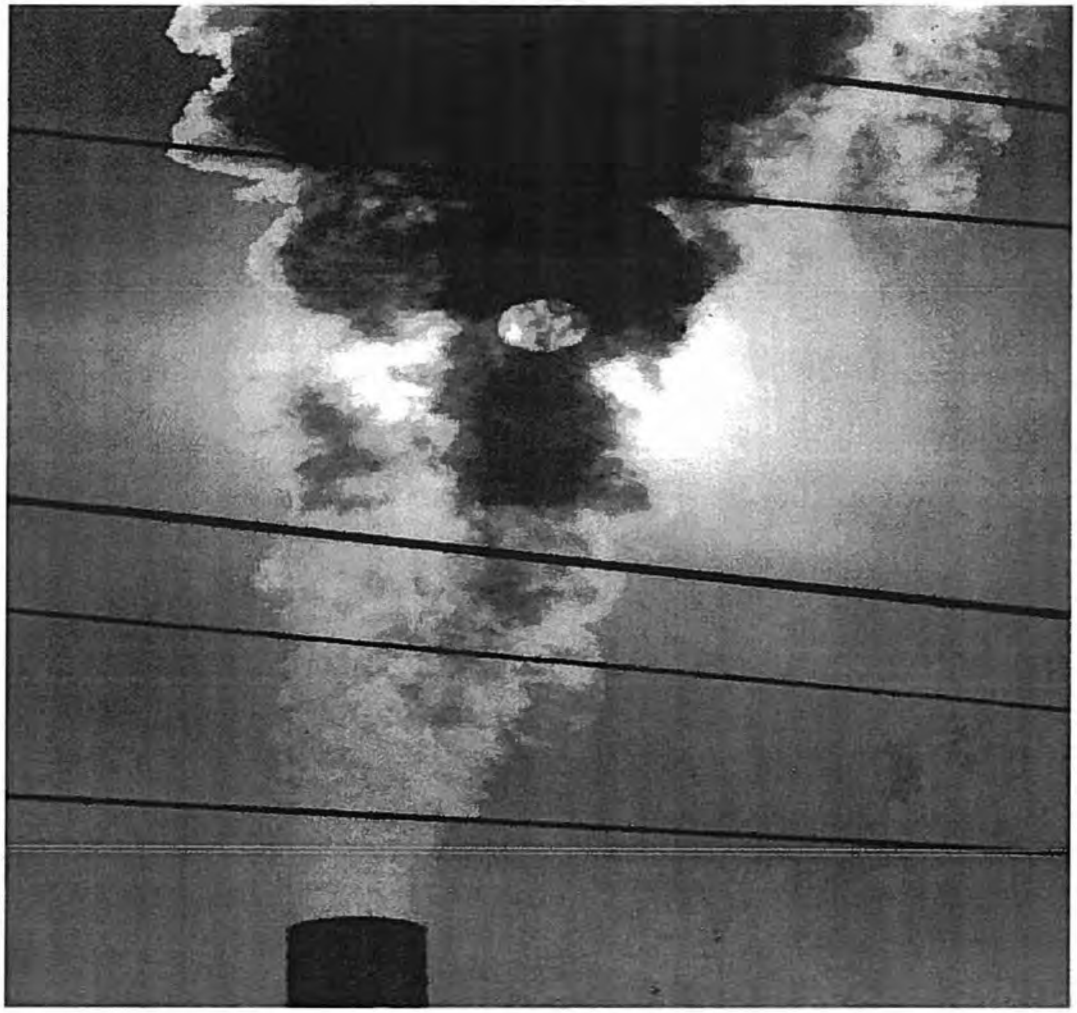
EXHIBIT 1

to

PETITION FOR RECONSIDERATION

DIRTY KILOWATTS

America's Most Polluting Power Plants



ENVIRONMENTAL INTEGRITY PROJECT

July 2007

About the Environmental Integrity Project

The Environmental Integrity Project (EIP) is a nonpartisan, nonprofit organization dedicated to more effective enforcement of environmental laws and to the prevention of political interference with those laws. EIP is headed by Eric Schaeffer, who directed the U.S. Environmental Protection Agency's Office of Regulatory Enforcement until 2002. EIP's research and reports shed light on how environmental laws affect public health. EIP works closely with communities seeking to enforce those laws.

Acknowledgements

We are grateful for the support of Changing Horizons, Civil Society Institute, the Magnolia Charitable Trust, The John Merck Fund, and the Rockefeller Family Fund. Environmental Integrity Project interns Jill Creamer, Chris McChesney, and Saurabh Aneja contributed to this report.

Data Limitations

EIP's rankings of the nation's dirtiest power plants are based on company self-reported data obtained through publicly accessible U.S. Environmental Protection Agency and U.S. Department of Energy websites. Occasionally, government data may contain errors, either because information is inaccurately reported or incorrectly transcribed by agencies. EIP is committed to ensuring that the data we present are as accurate as possible, and we will correct any errors that are verifiable.

Photo credits: Power plant photos by Martin Edmonds, Jesse Gibb, Sandy Bell, John Wellner, and Albert Koehl, courtesy of Ontario Clean Air Alliance; Asthma, iceberg, and smog photos courtesy of United States Environmental Protection Agency and National Oceanic and Atmospheric Administration; Fish advisory photo courtesy of Clean Water Action.

Questions and comments can be directed to ilevin@environmentalintegrity.org

ENVIRONMENTAL INTEGRITY PROJECT
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Introduction

Nationwide, the power plants that provide electricity to run our homes, businesses, and factories also account for 40 percent of carbon dioxide, roughly two thirds of sulfur dioxide, 22 percent of nitrogen oxides, and roughly a third of all mercury emissions. This report ranks America's dirtiest power plants, based on company-reported data.

While Congress is poised to seriously consider legislation to limit the greenhouse gases that made 2006 the hottest year on record,[1] the electric power industry is racing to build a new fleet of coal-fired power plants that rely on conventional combustion technologies that would only accelerate global warming. Once utility companies secure their air pollution permits, we can expect them to argue that these new plants should be "grandfathered," or exempt from any pending limits on greenhouse gases.

We've been through this before. When the original Clean Air Act was passed in 1970, the electric utility industry persuaded Congress to not impose strict pollution controls on old power plants, because they would soon be replaced by newer state-of-the-art facilities. Yet despite the industry's promises, many of the nation's oldest and dirtiest power plants continue to operate today.

Power plants are major contributors to global warming, emitting billions of tons of carbon dioxide (CO2) each year. In addition, power plants emit millions of tons of sulfur dioxide (SO2) and nitrogen oxides (NOx), pollutants that trigger asthma attacks and contribute to lung and heart disease, and cause smog and haze in cities and national parks. And, power plants emit dangerous toxins like mercury, a neurotoxin especially harmful to children and developing fetuses.

Data from the U.S. Environmental Protection Agency (EPA) and the Department of Energy's Energy Information Administration (EIA) show that a disproportionate share of emissions comes from a handful of old plants that have been slow to install modern pollution controls, or which operate inefficiently. This report ranks the top fifty power plant polluters for sulfur dioxide, nitrogen oxides, carbon dioxide, and mercury, according to:

- *Emission rate*, which measures the amount of pollution per megawatt-hour of electricity generated, and
- *Total* annual amount of each pollutant emitted, which measures the gross impact on public health and the environment.

A complete listing of all 378 of the nation's largest plants ranked for this report is included as Appendix A.

Some electric power companies have made long-term commitments to clean up their plants, either to settle legal actions or in anticipation of future regulation. Many companies are making business decisions to upgrade pollution controls, as prices of pollution credits, or "allowances," under federal cap-and-trade programs, continue to rise. EPA's Clean Air Interstate Rule (CAIR) sets emissions caps for sulfur dioxide and nitrogen oxides in eastern states, but the pollution reductions will not be realized until well beyond 2015. Unfortunately, not all power companies are committed to cleaning up their dirtiest plants, choosing instead to buy their way out of emissions caps.

Pollution controls that dramatically reduce emissions of conventional pollutants, like sulfur dioxide and mercury, are widely available and already being used at some plants. Carbon dioxide reductions can be realized through efficiency measures and energy conservation, as a start. But, until the public and policymakers hold the electric utility industry to its promised cleanup of the nation's oldest and dirtiest power plants, Americans will continue to bear unnecessary health and environmental costs.

Highlights

In 2006, EPA tracked more than 1,400 fossil-fired power plants of varying sizes through its Acid Rain Program. According to EPA data, carbon dioxide emissions saw a slight decline between 2005 and 2006, but there is no evidence of a long-term downward trend. In fact, CO_2 emissions are projected to steadily increase over the next two decades.[2] Overall emissions of sulfur dioxide declined by eight percent from 2005, to 9.4 million tons a year. Emissions of nitrogen oxides are slowly declining. Power plant mercury emissions are holding steady at roughly 48 tons per year.

Power Plant Emissions (2002-2006)

	2002	2003	2004	2005	2006
SO2 tons*	10.20 M	10.60 M	10.26 M	10.22 M	9.40 M
CO2 tons*	2.42 B	2.47 B	2.48 B	2.54 B	2.49 B
NOx tons*	4.47 M	4.17 M	3.76 M	3.63 M	3.49 M
Hg tons**	45.2	45.3	47.3	48.3	-

* Source: EPA Acid Rain Program Emissions Tracking System (all plants)
** Source: EPA's Toxics Release Inventory; 2006 data not available

This report ranks each of the 378 largest plants (i.e., those plants generating at least 2 million megawatt-hours in 2006) for which both the most recent EPA emissions data *and* Energy Information Administration (EIA) electric generation data are publicly available. Based on these two sources, the report ranks each plant based on emission rates, or pounds of pollutant for each megawatt-hour (or million megawatt-hours, in the case of mercury) the plant produced.

Carbon Dioxide: Emissions Holding Steady

Not surprisingly, given the absence of any federal standards, carbon dioxide emissions from power plants appear to be holding steady at roughly 2.5 billion tons per year. About two-thirds of the heat energy that is consumed at a typical coal-fired power plant is wasted, and that inefficiency contributes directly to high CO_2 emissions from these facilities. Eliminating CO_2 emissions from existing power plants is currently technically unfeasible, but reducing electricity demand, through energy efficiency and conservation measures, would yield significant CO_2 reductions in the near-term, while new technologies develop.

A wave of new coal-fired power plants are being permitted and built across the country. A U.S. Department of Energy National Energy Technology Laboratory (http://www.netl.doe.gov/) publication tracking more than 150 such projects is attached as Appendix B. Absent aggressive national climate policy and the retirement of existing facilities, these new coal plants will contribute to a projected 34 percent increase in U.S. carbon dioxide emissions from 2005 to 2030.[3]

Sulfur Dioxide: Good News and Bad News

A handful of old, dirty power plants continue to generate a disproportionate amount of SO_2 pollution.

The good news is that thirty-seven years after the Clean Air Act was passed, power plants are finally starting to clean up their sulfur dioxide pollution, thanks to a combination of factors including enforcement actions, tough state laws, and reductions anticipated from EPA's Clean Air Interstate Rule (CAIR), a rule designed to cap SO_2 and NOx emissions in states east of the Mississippi.[4]

CAIR establishes a two-phase cap for SO_2, culminating in 2.5 million tons in eastern states in 2015. However, due to early reductions and banking of credits for use in later years, the SO_2 cap is unlikely to be met until well beyond 2015. Power companies are beginning to install scrubbers that will reduce sulfur dioxide by as much as 90 percent at some of the dirtiest facilities. For example, roughly half of the top fifty highest SO_2 emitters in terms of total tons are expected to have scrubbers in operation by 2010.

Nitrogen Oxides: Slow but Steady Progress in Most Eastern States

Nitrogen oxides emissions dropped slightly in 2006, and are expected to decline still further in eastern states over the next five years. Rules to limit the interstate transport of NOx during the summer ozone season in eastern states were adopted in the late nineties (the "NOx SIP Call"), and emission ceilings have been ratcheted steadily downward by law. Also, the CAIR rule moves the Acid Rain (Phase 1) NOx cap forward a year, to 2009, and sets a 1.3 million ton cap in 2015. Lastly, tough new state standards like the Maryland Healthy Air Act should lead to additional reductions in year-round NOx emissions.

Unfortunately, this trend is not apparent in western states where neither CAIR nor ozone transport rules apply. Not surprisingly, many plants with high NOx emission are located in these states, and in states not included in the NOx "SIP Call," such as North Dakota, Minnesota, and Florida.

Mercury: Emissions Levels Remain Steady at 48 Tons Per Year

Taken together, all of the 486 plants that are tracked in EPA's Toxics Release Inventory reported 48.3 tons of mercury air emissions in 2005. Of these, this report ranks only the 274 "large" power plants (i.e., those plants that generated at least 2 million MWh in 2005). These largest 274 plants emitted 43.5 tons of mercury in 2005.

Many plants are installing scrubbers to control sulfur dioxide, and mercury emissions should decline as a co-benefit of SO_2 controls. But, EPA's new power plant mercury rule is unlikely to have any measurable benefit in the short-term. Power plant mercury emissions are expected to decline to roughly 24 tons in 2020 – significantly higher than EPA's so-called cap of 15 tons by 2018, as power plants "bank" pollution allowances in the early years of the rule's implementation. Widespread use of banked allowances means that EPA's cap of 15 tons will likely not be met until 2026 or beyond.

Top 50

Power Plant

CO_2 Polluters

Table 1, *Top 50 Dirtiest Power Plants for CO_2*, ranks the 50 power plants with the highest *emission rates*, expressed as pounds of carbon dioxide per megawatt-hour of electricity generation. Table 2, *Top 50 Polluting Power Plants for CO_2*, ranks the top 50 emitters, by *total* tons emitted, without regard to how much electricity the plants generated. All rankings include only those facilities that produced at least 2 million MWh of electricity in 2006.

Emission Rate Highlights

- The disparity among all 378 plants that generated more than 2 million MWh in 2006 is not as wide as for other (regulated) pollutants. In other words, generally speaking, coal-fired power plants are equally inefficient when it comes to CO_2. Thus, of 378 plants ranked, the top 50 plants accounted for 13.7 percent of emissions and generated 11.7 percent of electricity.

- Nevada Power's Reid Gardner plant topped the list, with an emission rate of more than 3,500 pounds per megawatt-hour.

- Large lignite-burning power plants in North Dakota and Texas rank among the worst CO_2 polluters based on emission rate. Lignite is low grade fuel, abundant in places like Texas and North Dakota; lignite's comparatively low BTU (heat) value means more CO_2 for the electricity it generates.

Total Tons Highlights

Because CO_2 pollution is not yet federally regulated, power plants do not control emissions. All 378 plants ranked, on average, emit roughly a ton of carbon dioxide for every megawatt-hour of electricity they produce, and, as one would expect, the largest fossil fuel fired plants emit the most CO_2.

Nine Plants Make Both Lists

- Plants in Texas (TXU's Martin Lake and Monticello), Montana (Colstrip), Minnesota (Sherburne County), Wyoming (Laramie River), Indiana (Schahfer), Florida (Big Bend), Nebraska (Gerald Gentleman), and North Dakota (Coal Creek), rank in the top 50 for both emissions rate and overall tons of CO_2.

Increased Efficiency Will Reduce Environmental Impacts

Carbon dioxide, one of several greenhouse gases that contributes to climate change, is released into the atmosphere when fossil fuels (oil, natural gas, and coal), wood, and solid waste are burned.[5] Power plants are responsible for about 40 percent of all man-made CO_2 emissions in the nation, and unlike emissions of SO_2 and NOx, the electric power industry's CO_2 emissions are projected to steadily rise.

Power plant CO_2 emissions are directly linked to the efficiency with which fossil fuels are converted into electricity, and coal-fired power plants are inherently inefficient. A typical power plant converts only about a third of the energy contained in coal into electricity, while the remainder is emitted as waste heat.[6] In fact, coal-fired power plant efficiency has remained largely unchanged since the mid 1960's.

A sound national policy aimed at addressing climate change must hold the electric power industry to the promise it made more than a generation ago: it is time to permanently retire the relative fraction of the nation's dirtiest electricity generating units. Next, smarter building codes, and funding low-cost conservation efforts – such as weatherization of low-income homes, purchase and installation of more efficient home and business appliances – will reduce demand and yield greenhouse gas benefits.

If any new coal plants are built, they must be required to dramatically reduce carbon dioxide emissions from current levels. Carbon capture and sequestration (removing and storing the carbon either before or after the fuel is burned) and storing the carbon underground in perpetuity has promise, but has yet to be demonstrated as technically and economically feasible.[7] In the meantime, most efficiency improvements – and lower CO_2 emissions – can be achieved through currently available and economically viable technologies. For example, combined-cycle generators and combined heat and power systems capture and use "waste heat" to produce additional electricity; new "ultra-supercritical" designs for steam boilers, new materials, and gas turbines (instead of steam), which withstand higher temperatures and pressures, can improve power plant efficiency; and blending cleaner fuels with coal, such as natural gas and biomass, can further curb overall carbon dioxide emissions and double fossil-fuel-fired plants' thermal efficiency, up to 60 percent.[8]

Table 1. Top 50 Dirtiest Power Plants for CO_2 By Emission Rate - lbs CO_2/MWh (2006)

Rank	Facility Name	Facility Owner	State	CO2 (Tons)	CO2 Rank (Tons)	Net Generation (MWh)	Emission Rates
1	Reid Gardner	Nevada Power	NV	5,166,573.18	152	2,899,640.00	3,563.60
2	Sherburne	Northern States	MN	18,003,647.95	13	12,872,776.00	2,797.17
3	Warrick	Alcoa	IN	6,092,055.94	133	4,457,515.00	2,733.39
4	Wabash River	PSI Energy Inc	IN	5,708,663.78	140	4,250,856.00	2,685.89
5	Dave Johnston	PacifiCorp	WY	7,708,347.93	102	5,776,835.00	2,668.71
6	San Miguel	San Miguel	TX	3,901,767.83	198	2,937,194.00	2,656.80
7	Coal Creek	Great River	ND	11,094,477.64	50	8,403,311.00	2,640.50
8	Weston	Wisconsin Public	WI	4,421,567.29	180	3,415,522.00	2,589.10
9	Elmer Smith	Owensboro	KY	2,846,614.59	253	2,205,772.00	2,581.06
10	Eddystone	Exelon	PA	3,720,279.47	209	2,886,159.00	2,578.01
11	Coyote	Otter Tail	ND	3,658,089.28	211	2,844,480.00	2,572.06
12	Lawrence	Westar Energy	KS	4,181,451.56	188	3,257,371.00	2,567.38
13	Centralia	TransAlta	WA	7,974,563.74	94	6,214,950.00	2,566.25
14	Springerville	Tucson Electric	AZ	7,373,041.51	107	5,801,431.00	2,541.80
15	F B Culley	S. Indiana Gas	IN	2,946,368.23	248	2,326,502.00	2,532.87
16	Pulliam	Wisconsin Public	WI	2,988,738.14	246	2,362,947.00	2,529.67
17	Sandow	TXU Generation	TX	4,901,916.53	159	3,878,580.00	2,527.69
18	R D Morrow	S. Mississippi El Pwr	MS	3,328,669.06	227	2,636,912.00	2,524.67
19	J T Deely	San Antonio	TX	6,915,214.35	116	5,502,734.00	2,513.37
20	Coleman	Western KY	KY	3,404,056.90	225	2,712,034.00	2,510.33
21	Big Bend	Tampa Electric	FL	11,760,766.40	45	9,422,708.00	2,496.26
22	Havana	Dynegy Midwest	IL	3,018,603.20	244	2,427,926.00	2,486.57
23	Elrama	Orion Power	PA	2,671,697.98	264	2,151,894.00	2,483.11
24	Grand River	Grand River Dam	OK	7,625,549.35	105	6,151,201.00	2,479.37
25	Huntley Power	NRG Huntley	NY	3,301,283.04	228	2,666,529.00	2,476.09
26	Colstrip	PP&L Montana	MT	18,240,485.45	12	14,764,749.00	2,470.82
27	Charles Lowman	Alabama Electric	AL	4,730,394.10	165	3,834,124.00	2,467.52
28	Leland Olds	Basin Electric	ND	4,808,205.20	163	3,904,544.00	2,462.88
29	Big Brown	TXU	TX	10,942,645.32	55	8,911,676.00	2,455.80
30	Red Hills	Choctaw	MS	3,921,216.15	197	3,201,074.00	2,449.94
31	R M Schahfer	Northern Indiana	IN	11,850,737.46	44	9,675,831.00	2,449.55
32	Bay Shore	FirstEnergy	OH	5,393,977.32	147	4,407,217.00	2,447.79
33	Antelope Valley	Basin Electric	ND	8,696,067.31	81	7,106,993.00	2,447.19
34	Bailly	Northern Indiana	IN	2,622,285.45	268	2,144,456.00	2,445.64
35	J R Whiting	Consumers	MI	2,905,548.93	250	2,378,504.00	2,443.17
36	Montrose	Kansas City	MO	3,803,833.46	205	3,114,207.00	2,442.89
37	Monticello	TXU	TX	18,268,348.39	11	14,961,282.00	2,442.08
38	Wyodak	PacifiCorp	WY	2,872,883.11	252	2,353,507.00	2,441.36
39	Apache Station	Arizona Electric	AZ	3,452,791.33	222	2,843,773.00	2,428.32
40	Hayden	Pb Service of Colorado	CO	4,252,581.02	186	3,502,621.00	2,428.23
41	Pleasant Prairie	Wisconsin	WI	9,078,101.87	75	7,523,070.00	2,413.40
42	Milton R Young	Minnkota Power	ND	5,862,979.09	136	4,861,874.00	2,411.82
43	Powerton	MW Generations	IL	9,140,630.61	71	7,642,897.00	2,391.93
44	Martin Lake	TXU	TX	21,301,393.26	5	17,821,177.00	2,390.57
45	Presque Isle	Wisconsin Electric	MI	3,984,921.53	194	3,334,963.00	2,389.78
46	Laramie River	Basin Electric	WY	15,248,625.94	25	12,777,567.00	2,386.78
47	Ottumwa	Interstate Power	IA	4,714,087.93	166	3,952,075.00	2,385.63
48	Big Stone	Otter Tail	SD	3,784,491.54	207	3,174,012.00	2,384.67
49	Edgewater (4050)	Wisconsin Power	WI	5,103,545.06	154	4,281,210.00	2,384.16
50	Gerald Gentleman	Nebraska Public	NE	11,192,809.15	48	9,422,664.00	2,375.72
Total				340,887,590.85 tons		272,359,846 MWh	

Table 2. Top 50 Polluting Power Plants for CO_2 By Tons CO_2 (2006)

Rank (Tons)	Facility Name	Facility Owner	State	CO2 Tons	Rank (lbs/MWh)
1	Scherer	Southern/Georgia Power	GA	25,298,498.73	118
2	James H Miller Jr.	Southern/Alabama Power	AL	23,466,022.08	126
3	Bowen	Georgia Power	GA	22,756,191.48	201
4	Gibson	PSI Energy	IN	21,447,979.54	232
5	Martin Lake	TXU	TX	21,301,393.26	44
6	W A Parish	NRG Energy	TX	21,076,082.00	166
7	Rockport	American Electric Power	IN	20,181,544.90	208
8	Navajo	Salt River Project	AZ	20,071,580.51	75
9	Cumberland	Tennessee Valley	TN	19,049,067.53	194
10	John E Amos	Appalachian Power	WV	18,798,260.98	240
11	Monticello	TXU	TX	18,268,348.39	37
12	Colstrip	PP&L Montana	MT	18,240,485.45	26
13	Sherburne County	Northern States Power	MN	18,003,647.95	2
14	Labadie	Ameren- Union Electric	MO	17,458,154.23	236
15	Monroe	Detroit Edison	MI	17,401,929.08	223
16	Bruce Mansfield	First Energy Company	PA	17,375,622.88	243
17	Gen J M Gavin	Ohio Power	OH	16,997,448.75	189
18	Four Corners	Arizona Public Service	NM	16,395,797.19	186
19	Jeffrey Energy	Westar Energy	KS	16,239,424.98	84
20	Intermountain	Los Angeles (City of)	UT	16,035,530.05	104
21	Crystal River	Progress Energy Florida	FL	16,026,757.78	268
22	Jim Bridger	Pacificorp	WY	15,884,734.06	152
23	W H Sammis	FirstEnergy Generation	OH	15,761,761.88	199
24	Paradise	Tennessee Valley	KY	15,497,610.30	145
25	Laramie River	Basin Electric Power	WY	15,248,625.94	46
26	Roxboro	Progress Energy	NC	15,201,898.73	200
27	Big Cajun 2	Louisiana Generating	LA	14,620,639.45	82
28	Belews Creek	Duke Energy Corp	NC	14,034,728.65	252
29	Conemaugh	Reliant Energy NE	PA	13,991,063.97	215
30	J M Stuart	Dayton Power & Light	OH	13,710,852.60	242
31	Wansley (6052)	Southern/Georgia Power	GA	13,612,837.50	134
32	Harrison Power	Allegheny Energy	WV	13,450,027.47	219
33	Baldwin Energy	Dynegy Midwest	IL	13,250,175.41	159
34	Limestone	NRG Texas	TX	13,055,769.41	184
35	San Juan	Public Service Co of NM	NM	13,054,091.35	160
36	Ghent	Kentucky Utilities Co	KY	12,933,317.73	150
37	Petersburg	Indianapolis Power & Light	IN	12,826,618.08	77
38	Independence	Entergy Arkansas	AR	12,485,093.55	67
39	Mount Storm	Dominion Virginia Power	WV	12,464,709.03	154
40	Barry	Southern/Alabama Power	AL	12,449,918.39	259
41	E C Gaston	Southern/Alabama Power	AL	12,345,694.83	124
42	Keystone	Reliant Energy NE	PA	12,271,116.40	226
43	Homer City	Midwest Generations	PA	11,970,801.97	218
44	R M Schahfer	Northern Indiana	IN	11,850,737.46	31
45	Big Bend	Tampa Electric Company	FL	11,760,766.40	21
46	Marshall	Duke Energy Corp	NC	11,425,787.60	257
47	Craig	Tri-State G & T Assn Inc	CO	11,322,684.57	66
48	Gerald Gentleman	Nebraska Public Power	NE	11,192,809.15	50
49	Sam Seymour	Lower CO River	TX	11,191,253.23	96
50	Coal Creek	Great River Energy	ND	11,094,477.64	7
Total				781,850,370.49 tons	

Top 50

Power Plant

SO_2 Polluters

Table 3, *Top 50 Dirtiest Power Plants for SO_2*, ranks the 50 power plants with the highest *emission rates*, expressed as pounds of sulfur dioxide per megawatt-hour of electricity generation. Table 4 *Top 50 Polluting Power Plants for SO_2*, ranks the top 50 emitters, by *total* tons emitted, without regard to how much electricity the plant generated. All rankings include only those facilities that reported emissions to EPA and produced at least 2 million MWh of electricity in 2006.

Emission Rate Highlights

- The top 50 plants averaged 21.1 pounds of sulfur dioxide per megawatt-hour, compared to only *one* pound per megawatt-hour for similar plants equipped with state of the art scrubbers.
- PSI Energy's Gallagher plant, in Indiana, claimed the top spot as the nation's dirtiest power plant, generating just over 40 pounds of sulfur dioxide per megawatt-hour of electricity.
- Indiana (5 plants), Ohio (8 plants), Pennsylvania (8 plants), and Georgia (6 plants) have the heaviest concentrations of the dirtiest plants in the nation for SO_2. Together, these four states accounted for more than half of all the top 50 emitters.
- Of all 378 plants ranked, the top 50 plants with the worst emission rates accounted for 40 percent of SO_2 emissions, but only 13.7 percent of electric generation.

Total Tons Highlights

- Of all 378 plants ranked, the top fifty plants with the highest overall emissions accounted for more than half (4.4 million of the 8.4 million tons!) of SO_2 emissions, but only 26.5 percent of electric generation.
- Southern Company's Bowen plant in Georgia continued to lead the nation as the top SO_2 emitter, with a whopping 206,441 tons in 2006 – 20,000 tons more than it emitted in 2005, and 40,000 tons more than it emitted in 2004. Reliant's Keystone plant in Pennsylvania was the number two highest emitter, with more than 160,000 tons of SO_2. Both these plants are expected to install scrubbers by 2010, which should substantially bring down SO_2 emissions.
- Pennsylvania was home to four of the top 10 highest emitters.
- Just five states, Ohio (9), Indiana (7), Pennsylvania (5), Georgia (4), and Texas (4), accounted for more than half of the top 50 highest emitters.

The Biggest and the Dirtiest SO_2 Polluters

Many of the nation's dirtiest plants, based on emission rates, are also among the largest polluters, in terms of total tons. The chart below shows the 27 power plants that appear on both top 50 lists for SO_2.

Plants Ranked in Top 50 for Emission Rate and Total Tons SO_2 (2006)

State	Power Plants
Alabama	Gaston, Gorgas
Georgia	Harllee Branch, Bowen, Wansley, Yates
Indiana	Cayuga, Gallagher, Warrick[9], Wabash River
Maryland	Morgantown
Ohio	Beckjord, Cardinal, Conesville, Eastlake, Kyger Creek, Miami Fort, Muskingum River
Pennsylvania	Brunner Island, Hatfield's Ferry, Homer City, Keystone, Montour
Tennessee	Johnsonville
Texas	Big Brown
Virginia	Chesterfield
West Virginia	Fort Martin

Health and Environmental Effects

Power plants, especially those that burn coal, are by far the largest single contributor of SO_2 pollution in the United States, accounting for approximately 67 percent of all SO_2 emissions nationwide.[10] Sulfates (from SO_2) are major components of the fine particle pollution that plagues many parts of the country, especially communities nearby or directly downwind of coal-fired power plants. Sulfur dioxide also interacts with NOx to form nitric and sulfuric acids, commonly known as acid rain, which damages forests and acidifies soil and waterways.

Harvard School of Public Health studies have shown that SO_2 emissions from power plants significantly harm the cardiovascular and respiratory health of people who live near the plants. According to EPA studies, fine particle pollution from power plants results in thousands of premature deaths each year.[11]

Scrubbing: A Cleaner Alternative

Scrubbing is a loose term that describes an array of air pollution control devices that rely on a chemical reaction with a sorbent to remove pollutants, including sulfur dioxide, acid gases, and air toxics, from the process gas stream. For SO_2 removal, these devices are usually called flue gas desulfurization (FGD) systems, or simply, scrubbers.

"Wet" scrubbers, which use liquid to trap particles and gases in the exhaust stream, can reduce SO_2 by 98-99 percent, and "dry" scrubbers reduce SO_2 in the range of 90-95 percent.[12] According to the White House, scrubbing to eliminate sulfur dioxide is one of the most cost-effective ways to reduce public health risks. Vice President Cheney's *National Energy Policy Report* found that scrubbers could remove sulfur dioxide for less than $300 per ton,[13] while the White House Office of Management and Budget (OMB) estimates that every ton of SO_2 removed yields a public health benefit of $7,300.[14] This OMB estimate is based *only* on reduced premature death from heart and lung disease, and does not even account for the added benefits of reducing acid rain, crop damage, and visibility impairments, which have not been monetized.

Large coal plants equipped with scrubbers have shown that clean power is achievable. For example, Allegheny Energy's Conemaugh plant in Pennsylvania and Harrison plant in West Virginia, and Dominion's Mount Storm plant in West Virginia, all have large coal-fired units equipped with wet limestone scrubbers. These plants are achieving emission rates of approximately one pound per MWh, well below the top 50 plants' 21 pounds per MWh average.

Scrubbers to be Installed at Many of the Dirtiest Plants

After years of delay, SO_2 emissions have begun to decline as a significant number of coal-fired power plants install scrubbers to meet deadlines imposed under federal and state clean air rules, or to resolve enforcement actions brought by EPA and states. Last year's (July 2006) *Dirty Kilowatts* report included a listing of plants that planned to install scrubbers, based on commercially-available information. That report can be found at http://www.environmentalintegrity.org/pub386.cfm.

A significant investment in the cleanup of the oldest and dirtiest power plants should substantially reduce emissions that are a primary source of the fine particulate matter pollution that triggers asthma attacks, heart disease, and premature death. The overall momentum toward SO_2 reductions is clearly good news, and can be attributed to several factors:

- The deadline for attaining EPA air quality standards to limit exposure to fine particle pollution will take effect in 2010. These standards were established in 1997, and upheld by a unanimous Supreme Court despite fierce opposition from the power industry and business lobby. The sulfur dioxide from power plants is a major contributor to fine particle pollution, and reducing those emissions is a key part of state strategies to achieve the deadlines. It takes an estimated two and a half years to design, install, test and begin operation of a scrubber; plants that have not yet made a commitment are unlikely to have a scrubber in operation by the 2010 deadline for meeting air quality standards that limit fine particle pollution.

- EPA's Clean Air Interstate Rule (CAIR) establishes a ceiling on power plant emissions in most eastern states. Nationwide, the caps established under CAIR are expected to reduce sulfur dioxide by about 3.6 million tons in 2010, and 3.8 million tons in 2015, with more significant reductions in eastern states. The rule allows plants to bank, buy, and sell the right to pollute under these emission ceilings, which will mean that emission reductions under CAIR are not evenly distributed.

- Some states have enacted their own requirements for power plant cleanup. For example, Duke Power expects to have scrubbers operating by 2008 at the Marshall and Belews Creek plants in North Carolina, to comply with the state's Clean Smokestacks Act.

- Some facilities are installing scrubbers to resolve enforcement actions for violation of New Source Review requirements. These include Ohio Edison's Sammis plant in Ohio, and Dominion's Chesterfield facility in Virginia.

Interestingly, a number of large sources of sulfur dioxide have yet to make commitments to install scrubbers by 2010, even where required to do so under state law. For example, Mirant mid-Atlantic has been silent about its cleanup plans for its three Maryland plants (Morgantown, Chalk Point, and Dickerson), even though state law requires a large reduction of sulfur dioxide no later than 2010. Other notorious polluters, like Alcoa's Warrick plant in Indiana, may be banking on their ability to avoid cleanup by purchasing pollution allowances from other states.

Table 3. Top 50 Dirtiest Power Plants for SO2 By Emission Rate – lbs SO2/MWh (2006)

Rank	Facility	Facility Owner	State	SO2 Tons	Rank (Tons)	Net Generation	Emission Rates (lbs/MWh)
1	R Gallagher	PSI Energy Inc	IN	50,819.12	49	2,516,769.00	40.38
2	Muskingum River	AEP- Ohio Power	OH	122,983.69	7	7,503,925.00	32.78
3	Warrick	Alcoa Generating	IN	72,858.61	35	4,457,515.00	32.69
4	Hatfields Ferry	Allegheny Energy	PA	135,082.22	4	9,345,925.00	28.91
5	Portland	Reliant Energy	PA	30,685.44	88	2,168,315.00	28.30
6	Wabash River	PSI Energy	IN	58,793.29	42	4,250,856.00	27.66
7	Shawville	Reliant Energy	PA	47,287.13	52	3,508,513.00	26.96
8	Cayuga	PSI Energy Inc	IN	83,173.55	28	6,233,855.00	26.68
9	Morgantown	Mirant Mid-Atlantic	MD	98,072.82	12	7,520,144.00	26.08
10	Keystone	Reliant Energy NE	PA	164,353.53	2	12,727,533.00	25.83
11	Avon Lake	Orion Power Midwest	OH	43,479.43	59	3,548,783.00	24.50
12	Harding Street	IN Power & Light	IN	46,346.21	55	3,862,890.00	24.00
13	Jefferies	SC Pub Serv Auth	SC	26,299.30	106	2,199,016.00	23.92
14	E W Brown	Kentucky Utilities	KY	45,191.44	57	3,805,154.00	23.75
15	Montour	PPL Montour	PA	129,356.79	6	10,916,977.00	23.70
16	Kammer	Ohio Power	WV	40,750.25	63	3,455,847.00	23.58
17	Cheswick	Orion Power Midwest	PA	32,372.65	83	2,814,375.00	23.01
18	E C Gaston	Alabama Power	AL	130,494.19	5	11,389,703.00	22.91
19	Dickerson	Mirant Mid-Atlantic	MD	35,954.36	73	3,151,758.00	22.82
20	Johnsonville	Tennessee Valley	TN	86,792.72	23	7,657,037.00	22.67
21	Fort Martin on	Allegheny Energy	WV	87,565.12	21	8,038,844.00	21.79
22	Yates	Southern/Georgia Power	GA	75,475.77	33	6,977,562.00	21.63
23	Big Brown	TXU	TX	96,221.28	13	8,911,676.00	21.59
24	Chalk Point	Mirant Chalk Point	MD	49,590.90	51	4,691,534.00	21.14
25	Merrimack	Public Service Co of NH	NH	32,725.99	82	3,161,701.00	20.70
26	Leland Olds	Basin Electric Power	ND	40,026.52	66	3,904,544.00	20.50
27	Brunner Island	PPL Brunner Island	PA	93,544.98	19	9,132,954.00	20.49
28	Walter C Beckjord	Cincinnati Gas & Electric	OH	62,479.84	40	6,149,996.00	20.32
29	Hammond	Georgia Power Co	GA	40,578.58	64	4,007,384.00	20.25
30	Conesville	Columbus Southern	OH	90,539.92	20	9,052,577.00	20.00
31	Yorktown Power	Dominion Virginia	VA	21,685.38	127	2,184,050.00	19.86
32	Gorgas	Southern/ AL Power	AL	81,267.58	30	8,320,379.00	19.53
33	Greene County	Alabama Power	AL	37,862.98	71	3,987,948.00	18.99
34	Eastlake	FirstEnergy Generation	OH	82,705.24	29	8,764,959.00	18.87
35	Harllee Branch	Georgia Power	GA	95,989.86	15	10,247,285.00	18.73
36	Miami Fort	Cincinnati Gas & Electric	OH	62,027.95	41	6,658,669.00	18.63
37	Canadys Steam	SCElectric&Gas	SC	22,984.11	119	2,474,373.00	18.58
38	Kyger Creek	Ohio Valley Electric	OH	67,156.74	36	7,340,708.00	18.30
39	Bowen	Georgia Power	GA	206,441.58	1	22,631,283.00	18.24
40	Homer City	Midwest Generations	PA	106,772.08	9	12,255,226.00	17.42
41	Anclote	Progress Energy Florida	FL	23,507.20	116	2,940,530.00	15.99
42	Phil Sporn	Appalachian Power	WV	39,740.99	68	5,066,133.00	15.69
43	Chesterfield	Dominion Virginia Power	VA	64,862.69	38	8,342,370.00	15.55
44	Wateree	SC Electric&Gas	SC	32,797.07	81	4,287,153.00	15.30
45	Jack McDonough	Georgia Power	GA	28,834.90	94	3,772,302.00	15.29
46	E D Edwards	Ameren Energy	IL	33,943.95	79	4,442,708.00	15.28
47	Wansley (6052)	Southern/Georgia Power	GA	96,200.21	14	12,617,286.00	15.25
48	Herbert A Wagner	Constellation Power	MD	19,768.67	141	2,612,814.00	15.13
49	Cardinal	Cardinal Operating	OH	86,879.54	22	11,490,833.00	15.12
50	Chesapeake	Dominion Virginia Power	VA	26,802.47	104	3,679,845.00	14.57
Total				3,388,126 tons		321,180,516 MWh	

Table 4. Top 50 Polluting Power Plants for SO2
By Tons SO2 (2006)

Rank (Tons)	Facility Name	Facility Owner	State	SO2 Tons	Rank (lbs/MWh)
1	Bowen	Georgia Power Co	GA	206,441.58	39
2	Keystone	Reliant Engy NE Management Co	PA	164,353.53	10
3	Gibson	PSI Energy, Inc	IN	155,056.84	56
4	Hatfields Ferry	Allegheny Energy Supply Co LLC	PA	135,082.22	4
5	E C Gaston	Southern/Alabama Power Company	AL	130,494.19	18
6	Montour	PPL Montour LLC	PA	129,356.79	15
7	Muskingum River	AEP- Ohio Power Co	OH	122,983.69	2
8	John E Amos	Appalachian Power Co	WV	117,299.29	73
9	Homer City	Midwest Generations EME LLC	PA	106,772.08	40
10	J M Stuart	Dayton Power & Light Co	OH	103,648.51	54
11	Monroe	Detroit Edison	MI	103,569.90	75
12	Morgantown	Mirant Mid-Atlantic LLC	MD	98,072.82	9
13	Big Brown	TXU	TX	96,221.28	23
14	Wansley (6052)	Southern Power- Georgia Power	GA	96,200.21	47
15	Harllee Branch	Georgia Power Co	GA	95,989.86	35
16	Crystal River	Progress Energy Florida Inc.	FL	95,548.18	105
17	Belews Creek	Duke Energy Corp	NC	95,290.17	66
18	Roxboro	Progress Energy Carolinas Inc	NC	94,626.99	64
19	Brunner Island	PPL Brunner Island LLC	PA	93,544.98	27
20	Conesville	Columbus Southern Power Co	OH	90,539.92	30
21	Fort Martin	Allegheny Energy Supply Co LLC	WV	87,565.12	21
22	Cardinal	Cardinal Operating Co.	OH	86,879.54	49
23	Johnsonville	Tennessee Valley Authority	TN	86,792.72	20
24	W H Sammis	FirstEnergy Generation Corp	OH	86,391.73	81
25	Marshall	Duke Energy Corp	NC	85,049.62	61
26	Paradise	Tennessee Valley Authority	KY	83,926.17	74
27	Rockport	Indiana Michigan Power	IN	83,543.43	110
28	Cayuga	PSI Energy Inc	IN	83,173.55	8
29	Eastlake	FirstEnergy Generation Corp	OH	82,705.24	34
30	Gorgas	Southern/Alabama Power Co	AL	81,267.58	32
31	Monticello	TXU	TX	77,537.60	87
32	Martin Lake	TXU	TX	77,419.26	106
33	Yates	Southern/Georgia Power Company	GA	75,475.77	22
34	Scherer	Southern /Georgia Power Company	GA	74,205.42	152
35	Warrick	Alcoa Generating Corp	IN	72,858.61	3
36	Kyger Creek	Ohio Valley Electric Corp	OH	67,156.74	38
37	Clifty Creek	Indiana-Kentucky Electric Corp	IN	65,371.76	51
38	Chesterfield	Dominion Virginia Power	VA	64,862.69	43
39	Jeffrey Energy	Westar Energy	KS	64,482.49	101
40	Walter C Beckjord	Cincinnati Gas & Electric Co	OH	62,479.84	28
41	Miami Fort	Cincinnati Gas & Electric Co	OH	62,027.95	36
42	Wabash River	PSI Energy Inc	IN	58,793.29	6
43	W A Parish	NRG Energy	TX	56,437.62	172
44	Kingston	Tennessee Valley Authority	TN	55,472.54	84
45	James H Miller Jr	Southern/Alabama Power Company	AL	53,379.50	190
46	Barry	Southern/Alabama Power Company	AL	52,621.21	133
47	Mitchell (WV)	Ohio Power Co	WV	52,005.49	58
48	Labadie	Ameren- Union Electric	MO	51,444.64	174
49	R Gallagher	PSI Energy Inc	IN	50,819.12	1
50	Ghent	Kentucky Utilities Company	KY	49912.69	109
Total				4,423,151.96 tons	

Top 50

Power Plant

NOx Polluters

Table 5, *Top 50 Dirtiest Power Plants for NOx,* ranks the 50 plants with the highest *emission rates,* expressed as pounds of nitrogen oxides per megawatt-hour. Table 6, *Top 50 Polluting Power Plants for NOx,* ranks the top 50 emitters, by *total* tons emitted, without regard to how much electricity the plant generated. Rankings only include those plants that generated at least 2 million MWh of electricity in 2006.

Emission Rate Highlights

- The top 50 plants had an average emission rate of 5.47 pounds of NOx per megawatt-hour, more than double the 2.57 lbs/MWh average for all 378 of the nation's largest power plants.

- Of the 378 plants, the top 50 accounted for 25 percent of all NOx emissions but only 11.7 percent of net electric generation.

- Northern Indiana's Bailly plant claimed the top spot, with more than 9 pounds of NOx for every megawatt-hour. As in previous years, Minnkota's Milton Young (North Dakota) and Otter Tail Power's Big Stone (South Dakota) also topped the list, with each plant reporting just over 9 pounds of NOx per megawatt-hour.

- Many plants in the top 50 are in states with less stringent NOx emission limits because they do not fall under the "NOx SIP call," a federal rule designed to reduce summertime ozone in many eastern U.S. states. (NOx is a precursor to ground-level ozone.) This shows, not surprisingly, that electric utilities do not reduce NOx emissions unless they are required by law to do so.

Total Tons Highlights

- Of the 378 plants ranked, the top 50 accounted for 41.5 percent of NOx emissions, and only 28.7 percent of net generation.

- Arizona Public Service Company's Four Corners (New Mexico), and TVA's Paradise (Kentucky) plants topped the list, emitting 44,658 tons and 43,022 tons, respectively.

Health and Environmental Effects

Electric utilities account for about 22 percent of all NOx emissions in the U.S.[15] Ground-level ozone, which is especially harmful to children and people with respiratory problems such as asthma, is formed when NOx and volatile organic compounds (VOCs) react in sunlight. NOx also reacts with ammonia, moisture, and other compounds to form fine particle pollution, which damages lung tissue and is linked to premature death. Small particles penetrate deeply into sensitive parts of the lungs and can cause or worsen respiratory disease such as emphysema and bronchitis, and aggravate heart disease.

NOx also increases nitrogen loading in water bodies, especially in sensitive coastal estuaries. Too much nitrogen accelerates eutrophication, which leads to oxygen depletion and kills fish. According to EPA, NOx emissions are one of the largest sources of nitrogen pollution in the Chesapeake Bay.[16]

NOx Controls: SCR and SNCR

Selective catalytic reduction (SCR), which uses a catalyst bed to reduce NOx to nitrogen and water, can cut NOx emissions by more than 90 percent. Selective non-catalytic reduction (SNCR), which reduces NOx to nitrogen and water using a reducing agent (typically ammonia or urea), achieves up to 75 percent NOx removal. According to the White House Office of Management and Budget, the public health benefit of reducing power plant NOx emissions amounts to $1,300 per ton, considering *only* the benefits of reduced mortality from fine particle pollution linked to heart and lung disease. This government estimate does not even account for the added benefits of reducing acid rain, crop damage, and visibility impairments, which have not been monetized.

Large coal plants equipped with NOx controls demonstrate that cleaner power is achievable. For example, TexasGenco's (formerly Reliant) W.A. Parish plant in Texas, has steadily lowered its NOx emissions and become one of the lowest emitting coal plants for NOx, through a combination of low NOx design features and SCR controls.[17] Ameren's Labadie plant in Missouri, has achieved one of the lowest NOx emission rates in the nation, slightly above one pound of NOx per megawatt-hour, without use of an SCR, using low NOx burners and other technologies.[18]

Driven by federal regulations aimed at further reducing summertime ozone, power plants are steadily lowering NOx emissions. Kansas City Power and Light's La Cygne plant, for example, expects that selective catalytic reduction, which was scheduled to be operational before the 2007 ozone season, will yield significant reductions.

Table 5. Top 50 Dirtiest Power Plants for NOx By Emission Rate – lbs NOx/MWh (2006)

Rank (lbs/MWh)	Facility Name	Facility Owner	State	NOx Tons	Rank (Tons)	Net Generation	Emission Rates
1	Bailly	Northern Indiana Pub Serv	IN	10,355.17	107	2,144,456.00	9.66
2	Big Stone	Otter Tail Power Co	SD	14,681.04	67	3,174,012.00	9.25
3	Milton R Young	Minnkota Power Coop Inc	ND	21,923.53	27	4,861,874.00	9.02
4	Coyote	Otter Tail Power Co	ND	11,291.32	99	2,844,480.00	7.94
5	New Madrid	Associated Electric Coop	MO	28,757.11	13	7,659,009.00	7.51
6	La Cygne	Kansas City Power & Light	KS	33,511.51	8	9,390,258.00	7.14
7	Pulliam	Wisconsin Public Service	WI	8,162.86	132	2,362,947.00	6.91
8	Black Dog	Northern States	MN	7,107.72	155	2,089,284.00	6.80
9	Powerton	Midwest Generations	IL	25,539.79	20	7,642,897.00	6.68
10	Big Bend	Tampa Electric Company	FL	30,713.94	11	9,422,708.00	6.52
11	Watson Electric	Mississippi Power Co	MS	15,683.30	57	4,878,069.00	6.43
12	Elmer Smith	Owensboro Municipal Utilities	KY	7,044.59	156	2,205,772.00	6.39
13	Kammer	Ohio Power Co	WV	10,798.12	104	3,455,847.00	6.25
14	Sibley	Aquila, Inc.	MO	9,134.68	123	3,047,029.00	6.00
15	R D Morrow	South Mississippi El Pwr	MS	7,896.33	137	2,636,912.00	5.99
16	Reid Gardner	Nevada Power Co	NV	8,643.12	127	2,899,640.00	5.96
17	Paradise	Tennessee Valley Authority	KY	43,022.35	2	14,537,458.00	5.92
18	Elrama	Orion Power Midwest LP	PA	6,295.93	173	2,151,894.00	5.85
19	Naughton	PacifiCorp	WY	14,168.09	72	4,929,916.00	5.75
20	Dave Johnston	PacifiCorp	WY	16,457.13	53	5,776,835.00	5.70
21	Charles R Lowman	Alabama Electric Coop Inc	AL	10,881.15	103	3,834,124.00	5.68
22	Four Corners	Arizona Public Service	NM	44,648.57	1	15,969,176.00	5.59
23	State Line	State Line Energy LLC	IN	7,288.09	152	2,696,781.00	5.41
24	Apache Station	Arizona Electric Pwr Coop Inc	AZ	7,593.13	142	2,843,773.00	5.34
25	Allen	Tennessee Valley Authority	TN	13,287.66	80	5,301,265.00	5.01
26	Boardman	Portland General Electric Co	OR	5,917.94	184	2,373,754.00	4.99
27	Hudson	PSEG Fossil LLC	NJ	7,459.41	146	3,023,550.00	4.93
28	Kyger Creek	Ohio Valley Electric Corp	OH	17,862.62	44	7,340,708.00	4.87
29	Leland Olds	Basin Electric Power Coop	ND	9,428.71	118	3,904,544.00	4.83
30	Grand River Dam	Grand River Dam Authority	OK	14,782.58	62	6,151,201.00	4.81
31	Jefferies	South Carolina Pub Service	SC	5,283.89	197	2,199,016.00	4.81
32	Cape Canaveral	Progress Energy Florida	FL	4,847.56	207	2,025,417.00	4.79
33	Seminole (136)	Seminole Electric Coop Inc	FL	22,719.01	24	9,495,696.00	4.79
34	Muskingum River	AEP- Ohio Power Co	OH	17,950.82	43	7,503,925.00	4.78
35	Johnsonville	Tennessee Valley Authority	TN	18,201.57	42	7,657,037.00	4.75
36	Clifty Creek	Indiana-Kentucky Electric	IN	21,661.70	29	9,128,635.00	4.75
37	Warrick	Alcoa	IN	10,363.73	106	4,457,515.00	4.65
38	St. Johns	JEA	FL	21,698.01	28	9,343,278.00	4.64
39	Dolet Hills	Central Louisiana	LA	10,890.92	102	4,715,236.00	4.62
40	L V Sutton	Progress Energy Carolinas	NC	6,345.04	170	2,767,637.00	4.59
41	Colstrip	PP&L Montana	MT	32,868.55	9	14,764,749.00	4.45
42	Anclote	Progress Energy Florida	FL	6,502.32	168	2,940,530.00	4.42
43	Chalk Point	Mirant Chalk Point	MD	10,354.86	108	4,691,534.00	4.41
44	San Juan	Pub Serv. Co of NM	NM	27,503.07	18	12,466,870.00	4.41
45	Kincaid Station	Dominion Energy	IL	11,811.55	96	5,375,239.00	4.39
46	Hayden	Public Service of CO	CO	7,691.35	139	3,502,621.00	4.39
47	Michigan City	Northern Indiana	IN	6,231.87	175	2,852,261.00	4.37
48	Presque Isle	Wisconsin Electric	MI	7,274.20	153	3,334,963.00	4.36
49	Coronado	Salt River Proj	AZ	12,754.20	87	5,888,365.00	4.33
50	Mitchell (WV)	Ohio Power Co	WV	16,396.77	55	7,609,049.00	4.31
Total				749,688.48 tons		274,269,746 MWh	

Table 6. Top 50 Polluting Power Plants for NOx
By Tons NOx (2006)

Rank (Tons)	Facility Name	Facility Owner	State	NOx Tons	Rank (lbs/MWh)
1	Four Corners	Arizona Public Service	NM	44,648.57	22
2	Paradise	Tennessee Valley	KY	43,022.35	17
3	Crystal River	Progress Energy Florida Inc.	FL	35,411.89	130
4	Navajo	Salt River Proj Ag I & P Dist	AZ	34,743.80	67
5	Cumberland	Tennessee Valley Authority	TN	34,359.77	95
6	Gen J M Gavin	Ohio Power	OH	33,960.37	62
7	John E Amos	Appalachian Power Co	WV	33,946.88	118
8	La Cygne	Kansas City Power & Light	KS	33,511.51	6
9	Colstrip	PP&L Montana	MT	32,868.55	41
10	Monroe	Detroit Edison	MI	31,808.64	106
11	Big Bend	Tampa Electric Company	FL	30,713.94	10
12	Intermountain	Los Angeles (City of)	UT	28,911.01	65
13	New Madrid	Associated Electric Coop Inc	MO	28,757.11	5
14	Bowen	Georgia Power Co	GA	28,636.08	184
15	Gibson	PSI Energy, Inc	IN	28,532.85	183
16	Rockport	Indiana Michigan Power	IN	28,124.04	165
17	Jim Bridger	Pacificorp	WY	28,053.82	90
18	San Juan	Public Service Co of NM	NM	27,503.07	44
19	Bruce Mansfield	Pennsylvania Power	PA	25,724.63	166
20	Powerton	Midwest Generations	IL	25,539.79	9
21	J M Stuart	Dayton Power & Light	OH	25,518.95	113
22	Sherburne County	Northern States Power	MN	25,459.35	68
23	Conemaugh	Reliant Engy NE	PA	23,369.36	127
24	Seminole (136)	Seminole Electric Coop Inc	FL	22,719.01	33
25	Jeffrey Energy	Westar Energy	KS	22,647.96	132
26	Mount Storm Power	Virginia Electric & Power	WV	22,463.70	84
27	Milton R Young	Minnkota Power Coop Inc	ND	21,923.53	3
28	St. Johns River	JEA	FL	21,698.01	38
29	Clifty Creek	Indiana-Kentucky Electric	IN	21,661.70	36
30	James H Miller Jr	Southern/ Alabama Power	AL	21,237.10	224
31	Belews Creek	Duke Energy Group	NC	21,179.50	170
32	Harrison	Allegheny Energy Supply	WV	21,154.23	138
33	Harllee Branch	Georgia Power Co	GA	20,960.64	61
34	Roxboro	Progress Energy Carolinas	NC	20,940.61	164
35	W H Sammis	FirstEnergy Generation	OH	20,591.84	176
36	Hatfields Ferry	Allegheny Energy Supply	PA	20,055.61	51
37	E C Gaston	Southern/AL Power Company	AL	19,838.52	111
38	Laramie River	Basin Electric Power	WY	19,781.16	137
39	Hunter	PacifiCorp	UT	18,828.93	83
40	Northeastern	Public Service Co of Oklahoma	OK	18,353.16	91
41	Shawnee	Tennessee Valley	KY	18,216.35	81
42	Johnsonville	Tennessee Valley	TN	18,201.57	35
43	Muskingum River	AEP- Ohio Power Co	OH	17,950.82	34
44	Kyger Creek	Ohio Valley Electric Corp	OH	17,862.62	28
45	Conesville	Columbus Southern Power	OH	17,860.71	69
46	Gerald Gentleman	Nebraska Public Power	NE	17,646.52	89
47	Scherer	Southern/Georgia Power	GA	17,364.70	249
48	Widows Creek	Tennessee Valley Authority	AL	17,183.64	103
49	Cardinal	Cardinal Operating Co.	OH	17,159.86	145
50	Craig	Tri-State G & T Assn Inc	CO	17,081.03	108
Total				1,245,689.36 tons	

Top 50

Power Plant

Mercury Polluters

EPA's Toxics Release Inventory (TRI) tracks mercury emissions for 486 electric generating facilities in 2005, the latest year for which data is publicly available. These plants reported 48.3 tons of mercury released into the atmosphere in 2005.

Table 7, *Top 50 Dirtiest Power Plants for Mercury,* ranks the 50 power plants with the highest *emission rates*, expressed as pounds of mercury per million megawatt-hours (MMWh). Table 8, *Top 50 Polluting Power Plants for Mercury,* ranks the top 50 emitters, by total pounds emitted, without regard to how much electricity the plant generated. Rankings include only power plants listed in EPA's TRI database that generated at least 2 million megawatt-hours of electricity in 2005.

Emission Rate Highlights

- For all plants ranked for mercury, the top 50 plants with the highest emission rates together emitted 16 tons of mercury – a third of all power plant mercury pollution – but generated less than 18 percent of the electricity.

- For the third year in a row, American Electric Power's Pirkey plant (Texas) and Reliant's Shawville plant (Pennsylvania) are the top two dirtiest plants based on mercury emission rates.

Total Pounds Highlights

- The top fifty power plant mercury polluters accounted for almost 21 tons, or 43 percent of the electric power industry's mercury emissions.

- TXU's Martin Lake (Texas) plant ranked number one, with 1,705 pounds of mercury emissions. Southern Company's Scherer plant (Georgia) came in second, emitting 1,662 pounds. Southern Company and TXU also shared the third place spot, reporting 1,595 pounds of mercury emissions from these companies' Miller (Alabama) and Monticello (Texas) plants.

Twenty-Three Plants Make Both "Top 50" Lists

Twenty-three plants in __ states ranked in the top 50 for both emission rate and total pounds emitted. These plants represent the "worst of the worst" in terms of mercury pollution, because they not only emit large quantities of the neurotoxin, but also put out more mercury per unit of electricity they produce, as compared to similar plants.

Plants Ranked in Top 50 for Emission Rate and Total Pounds Hg
2005

State	Power Plants
Alabama	Gorgas, Gaston, Miller, Greene County
Arizona	Coronado
Georgia	Scherer
Indiana	Rockport
Kansas	La Cygne
Louisiana	Big Cajun 2
Minnesota	Sherburne
North Dakota	Coal Creek, Milton R. Young
Ohio	Conesville, Cardinal
Pennsylvania	Shawville, Keystone
Texas	Pirkey, Big Brown, Sandow, Martin Lake, Monticello, Limestone
Wisconsin	Pleasant Prairie

- Two Texas power plants, TXU's Big Brown and American Electric Power's Pirkey, rank in the top 10 for both emission rate and total pounds.

Health Effects

Coal-fired power plants are the single largest source of mercury air pollution, accounting for roughly 40 percent of all mercury emissions nationwide.[19] Mercury is a highly toxic metal that, once released into the atmosphere, settles in lakes and rivers, where it moves up the food chain to humans. The Centers for Disease Control has found that roughly 10 percent of American women carry mercury concentrations at levels considered to put a fetus at risk of neurological damage.[20]

Mercury Removal

Activated carbon injection, which is commercially available and has been tested through the Department of Energy's Clean Coal Power Initiative, can achieve mercury reductions of 90 percent (and better when coupled with a fabric filter for particulate control) on both bituminous and sub-bituminous coals. In addition, mercury can be significantly reduced as a "co-benefit" of controls for other pollutants, such as fabric filters, SO_2 scrubbers, and selective catalytic reduction

Even though mercury removal is achievable. EPA has backed away from strict power plant mercury regulation, opting instead to implement a lax cap-and-trade scheme which would allow power plants to either reduce their own mercury pollution or buy credits from other plants. That rule is being challenged in court by sixteen states and several environmental groups and Indian Tribes. According to a recently commissioned study by the National Wildlife Federation, under EPA's cap-and-trade scheme, power plant mercury emissions would decline to roughly 24 tons in 2020 – significantly higher than EPA's so-called cap of 15 tons by 2018. The reason is that some power plants are expected to make early reductions in the first phase of the plan, and bank those pollution allowances for use in later years. Because electric power companies will use banked allowances when the final cap of 15 tons goes into effect, that level of emissions will likely will not be met until 2026 or beyond.[21]

Table 7. Top 50 Dirtiest Power Plants for Mercury (Hg) By Emission Rate – lbs Hg/million MWh (2005)

Rank	Facility	Owner	State	Hg(lbs)	Rank: Hg (lbs)	Net Generation (2005)	Rate
1	H.W. Pirkey	American Electric Power	TX	1142.00	8	4,993,706	228.69
2	Shawville Station	Reliant Energy	PA	691.00	28	3,199,780	215.95
3	Armstrong Power Station	Allegheny Energy Inc	PA	331.00	92	2,014,300	164.33
4	Hatfield Power Station	Allegheny Energy Inc	PA	454.00	56	2,889,720	157.11
5	Greene County Steam Plant	Alabama Power Co.	AL	606.60	34	3,912,748	155.03
6	Big Brown	TXU	TX	1196.00	6	8,549,082	139.9
7	Montrose	Kansas City Power	MO	444.30	59	3,342,902	132.91
8	Gorgas Steam Plant	Alabama Power Co.	AL	1004.10	12	7,910,063	126.94
9	Ottumwa Generating Station	IES Utilities Inc	IA	404.10	67	3,240,977	124.68
10	Twin Oaks	Twin Oak Power	TX	309.08	103	2,490,416	124.11
11	Holcomb Unit 1	Sunflower Power Electric	KS	327.20	94	2,684,906	121.87
12	Sandow Steam	TXU	TX	524.00	41	4,303,896	121.75
13	Monticello Steam	TXU	TX	1595.00	4	14,807,478	107.72
14	Keystone Power Plant	Reliant Energy	PA	1370.00	5	13,488,615	101.57
15	Conesville Plant	American Electric Power	OH	984.00	13	9,716,702	101.27
16	Pleasant Prairie	Wisc. Electric Pwr. Co.	WI	834.60	22	8,459,985	98.65
17	Coal Creek Station	Great River Energy	ND	858.50	20	8,708,890	98.58
18	Otter Tail Corp	Otter Tail Power Co.	ND	300.00	108	3,046,318	98.48
19	Milton R. Young Station	Minnkota Power Coop Inc	ND	502.00	46	5,117,830	98.09
20	Coronado	Salt River Project	AZ	582.00	35	6,070,915	95.87
21	Gaston Steam Plant	Alabama Power Company	AL	1077.40	11	11,273,347	95.57
22	San Miguel	TXU	TX	271.00	118	2,850,653	95.07
23	Martin Lake	TXU	TX	1705.00	1	18,250,189	93.42
24	Lacygne Generating Station	Great Plains Energy	KS	826.10	23	9,038,866	91.39
25	Avon Lake Power Plant	Reliant Energy	OH	321.88	96	3,542,468	90.86
26	Limestone Electric	NRG	TX	1089.20	10	12,759,023	85.37
27	R.D. Morrow Sr.	S. Mississippi El Pwr Assn	MS	211.40	152	2,551,303	82.86
28	Boardman Plant	Portland General Electric	OR	281.30	112	3,465,193	81.18
29	Springerville	Tuscon Electric Power	AZ	428.70	62	5,577,373	76.86
30	Big Cajun 2	NRG	LA	891.00	18	11,634,870	76.58
31	Ameren Meramec	Ameren – UE	MO	435.30	60	5,691,990	76.48
32	Miller Steam Plant	Alabama Power Co.	AL	1595.30	3	21,328,867	74.8
33	Dickerson	Mirant	MD	270.00	121	3,619,103	74.6
34	Gibbons Creek	Texas Municipal	TX	265.00	124	3,595,378	73.71
35	State Line Generating	State Line Energy	IN	200.00	157	2,749,201	72.75
36	Cardinal Plant	American Electric Power	OH	826.00	24	11,372,176	72.63
37	Leland Olds Station	Basin Electric	ND	340.00	89	4,816,732	70.59
38	Northern States	Norther States Power	MN	958.40	15	13,584,052	70.55
39	Scherer Steam Electric	Georgia Power	GA	1662.20	2	24,093,772	68.99
40	Columbia Energy Center	Alliant Energy	WI	460.21	55	6,699,039	68.7
41	George Neal South	Mid American Energy Co.	IA	260.00	127	3,953,550	65.76
42	Huntley	NRG Huntley Operations	NY	167.00	171	2,539,715	65.76
43	Rockport Plant	American Electric Power	IN	1179.00	7	17,942,286	65.71
44	Dominion Kincaid	Kincaid Generation	IL	400.00	70	6,138,622	65.16
45	Nebraska City Station	Omaha Public	NE	300.00	107	4,623,168	64.89
46	Antelope Valley Station	Basin Electric	ND	410.00	66	6,437,295	63.69
47	Michigan City	Northern Indiana Pub. Serv.	IN	162.00	173	2,545,676	63.64
48	Hugo	Western Farmers	OK	191.44	160	3,019,097	63.41
49	Newton Power Station	Ameren Energy	IL	462.60	54	7,297,242	63.39
50	George Neal North	Mid American Energy Co.	IA	400.00	69	6,325,167	63.24
Total				32,507 lbs		358,264,642 MWh	

Table 8. Top 50 Polluting Power Plants for Mercury (Hg) By Pounds Hg (2005)

Rank (lbs)	Facility	Owner	State	Hg(lbs)	Rank (lbs/MMwh)
1	Martin Lake	TXU Generation Co LP	TX	1705.00	25
2	Scherer Steam	Georgia Power	GA	1662.20	42
3	Miller Steam Plant	Alabama Power Co.	AL	1595.30	35
4	Monticello	TXU	TX	1595.00	15
5	Keystone Power Plant	Reliant Energy	PA	1370.00	16
6	Big Brown	TXU Generation Co LP	TX	1196.00	6
7	Rockport Plant	American Electric Power	IN	1179.00	46
8	H.W. Pirkey	American Electric Power	TX	1142.00	1
9	Amerenue Labadie	Ameren-UE	MO	1129.90	61
10	Limestone	Texas Genco II, LP	TX	1089.20	28
11	Gaston Steam Plant	Alabama Power Co.	AL	1077.40	23
12	Gorgas Steam Plant	Alabama Power Co.	AL	1004.10	9
13	Conesville Plant	American Electric Power	OH	984.00	17
14	Bowen Steam	Georgia Power Co	GA	966.90	120
15	Northern States Power Co.	Northern States Power Co	MN	958.40	41
16	W.A. Parish	Texas Genco II, LP	TX	957.00	98
17	Colstrip Steam Electric Station	PP&L Montana LLC	MT	920.00	69
18	Big Cajun 2	Louisiana Generating Plant	LA	891.00	33
19	Barry Steam Plant	Alabama Power Co.	AL	880.60	62
20	Coal Creek Station	Great River Energy	ND	858.50	19
21	Amos Plant	American Electric Power	WV	837.00	116
22	Pleasant Prairie Power Plant	Wisconsin Electric Power Co	WI	834.60	18
23	Lacygne Generating Station	Great Plains Energy	KS	826.10	26
24	Cardinal Plant	American Electric Power	OH	826.00	39
25	J.M. Stuart Station	Dayton Power & Light Co	OH	790.00	73
26	Monroe Power Plant	Detroit Edison Co.	MI	780.00	128
27	Jeffrey Energy Center	Westar Energy Inc.	KS	757.40	87
28	Shawville Station	Reliant Energy	PA	691.00	2
29	San Juan Generating Station	Public Service Co. of NM	NM	683.00	72
30	Roxboro Steam Electric Plant	Carolina Power and Light Co.	NC	670.00	111
31	Laramie River Station	Basin Electric Power Cooperative	WY	650.00	88
32	Brandon Shores & Wagner Complex	Constellation Power Source	MD	640.00	32
33	EME Homer City G	EME Homer City	PA	633.87	104
34	Greene County Steam Plant	Alabama Power Co.	AL	606.60	5
35	Coronado Generating Station	Salt River Project	AZ	582.00	22
36	White Bluff Generating Plant	Arkansaw Power	AR	581.40	56
37	Gibson Generating Station	Duke Energy Corp	IN	577.00	211
38	Four Corners	Public Service Co of NM	NM	562.70	162
39	Crystal River Energy Complex	Progress Energy	FL	550.00	213
40	Amerenue Rush Island Power Plant	Ameren-UE	MO	535.10	63
41	Sandow Steam Electric Station	TXU Generation Co LP	TX	524.00	13
42	Kammer/Mitchell Plants	American Electric Power	WV	511.30	8
43	OW Sommers/JT Deely/JK Spruce	San Antonio (City of)	TX	509.30	14
44	Gavin Plant	American Electric Power	OH	507.00	206
45	R.M. Schafer Generating Station	N. Indiana Public Service Co.	IN	505.00	102
46	Milton R. Young Station	Minnkota Power Coop Inc	ND	502.00	21
47	Edison International Powerton	Midwest Generations EME LLC	IL	501.78	76
48	IPL Petersburg	Indianapolis Power and Light Co.	IN	500.30	119
49	Conemaugh Power Plant	Reliant Energy	PA	500.00	145
50	Paradise Fossil Plant	U.S. TVA	KY	490.00	169
Total				41,826 lbs	

Data Sources and Methodology

The rankings in this report present a snapshot based on the most current publicly available data — 2006 data for SO_2, CO_2, and NOx, and 2005 data for mercury — from two federal agencies. The report ranks only large power plants (i.e. generating at least 2 million megawatt-hours) that reported emissions in EPA's Emission Tracking System. For SO2, CO_2, and NOx, we ranked 378 plants, and for mercury, we ranked roughly 274 plants. These plants account for most of the electric generation from the 1,000-plus power plants tracked by EPA. The vast majority of these large power plants are coal-fired.

Net electric generation and plant ownership data is drawn from the Energy Information Administration (EIA) within the Department of Energy, and can be publicly accessed at http://www.eia.doe.gov/. Net electric generation data was obtained from the EIA's "Power Plant Reports," specifically Forms EIA-906/920. These databases collect the fuel consumption, electric generation, and fuel stocks of all power plants in the United States with a generating capacity of one megawatt and greater. EIA tracks data for combined heat and power plants (typically industrial cogenerators, such as paper mills and refineries), while Form EIA-906 collects data from all-electric power plants. There are approximately 3,000 plants that file the Form EIA-906 annually.

Sulfur dioxide, carbon dioxide, and nitrogen oxides emissions data are from EPA's Acid Rain Program Emissions Tracking System (ETS). The database is a publicly accessible repository for SO_2, CO_2, and NOx data from the utility industry, and includes more than 1,000 power plants regulated under the Acid Rain Program and the NOx SIP Call. Additional information on these programs and ETS can be found on EPA's Clean Air Markets web page at http://www.epa.gov/airmarkets/.

Mercury data is derived from EPA's Toxics Release Inventory (TRI); the most current TRI data is for 2005.

All data is self-reported to these agencies by the utility industry.

Top 50 Rankings are for Large Plants — 2 million MWh or Greater

According to EIA, roughly 50 percent of all the electricity generated in the U.S. comes from coal-fired generation; nuclear generation contributed 20 percent; natural gas generated almost 18 percent; hydro-power provided close to 7 percent; petroleum accounted for 3 percent; and the remainder came from renewables (biomass, geothermal, solar, and wind) and other miscellaneous energy sources.[22]

Approximately 1,000 power plants throughout the United States report emissions to EPA's Acid Rain Program. These plants generate roughly 2.5 billion megawatt-hours of electricity, almost two-thirds of all the electricity generated in the United States.

EPA's Acid Rain Program tracks emissions from plants of varying size, from the largest facilities like the Scherer Plant in Georgia, which generated more than 23 million MWh, to small facilities that generated less than 1,000 megawatt-hours. The rankings in this report include only the 378 largest power plants listed in EPA's Emission Tracking System database for which 2006 emissions and net generation data is publicly available. For this report, we defined "large plants" as those that generated at least 2 million MWh in 2006 (year 2005 data is used for mercury).

Taken together, these 378 plants represent about a third of all power plants tracked in EPA's inventory, but they account for almost 90 percent of the electricity generated by the plants in EPA's inventory, and approximately half of total U.S. electric generation.

Appendix B lists the 378 plants by state, and also includes the primary fuel reported by each utility to EIA.

Data Limitations

Industry-reported emissions and net generation data may contain errors and omissions, either because information is inaccurately reported by power companies or incorrectly transcribed by agencies. EIP is committed to ensuring that the data we present are as accurate as possible, and we will correct any errors that are verifiable.

To assure that the data relied upon in this report is as accurate as possible, we compared emissions and generation data against prior year reports in order to identify potential inconsistencies. We also cross-referenced EIA and EPA databases using each plant's federal identification ("ORISPL") number, because plant names may differ slightly among various government databases. Finally, tracking company names and plant ownership within the utility industry is always challenging, and we have used our best efforts to update plant ownership information in each of the Top 50 ranking tables, based on company websites and other publicly available electric utility information.

Endnotes

[1] *See*, Climate Experts Worry as 2006 Is Hottest Year on Record in U.S., Marc Kaufman, Washington Post, Wednesday, January 10, 2007; Page A01

[2] *Annual Energy Outlook 2007 with Projections to 2030*, US Energy Information Administration, available at: http://www.eia.doe.gov/oiaf/aeo/emission.html.

[3] *Id.*

[4] *See*, http://www.epa.gov/CAIR/.

[5] According to the EPA's most recent Inventory of U.S. Greenhouse Gas Emissions, electricity generators consume about 34 percent of U.S. fossil fuel energy and emit roughly 40 percent of all CO2 from fossil fuel combustion. Electricity generators rely on coal for more than half of their total energy requirements, and electric generation accounts for 94 percent of all coal consumed in the United States. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2004* (April 2006) USEPA #430-R-06-002, p. ES-8,
available at: http://yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/RAMR6MBLP4/$File/06ES.pdf.

[6] *See*, "Carbon Dioxide Emissions from the Generation of Electric Power in the United States," July 2000, Department of Energy, Environmental Protection Agency, available at:
http://www.eia.doe.gov/cneaf/electricity/page/co2_report/co2report.html.

[7] Bohm, M.C., H.J. Herzog, J.E. Parsons and R.C. Sekar, "Capture-ready coal plants - Options, technologies and economics," International Journal of Greenhouse Gas Control, Vol 1, pages 113-120, (2007). Available at: http://sequestration.mit.edu/research/real_options.html.

[8] *See*, "Controlling Power Plant CO2 Emissions: A Long Range View," by John Marion and Nsakala ya Nsakala, ALSTOM Power Plant Laboratories, Windsor, CT (U.S. offices), available at:
http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/1b2.pdf.

[9] Alcoa's Warrick plant has one generating unit that is co-owned with another utility. Alcoa reports all of its emissions to EPA, but it only reports the electricity it actually "owns" to EIA. Therefore, emission rates for Alcoa's Warrick plant are slightly inflated. However, EIP has no information on the breakdown of electricity owned by Alcoa, and therefore presents the rankings for this plant based strictly on company self-reported government data.

[10] U.S. EPA, *Acid Rain Program 2002 Progress Report*, EPA-430-R-03-011, November 2003, available at http://www.epa.gov/airmarkets/cmprpt/arp02/2002report.pdf. *See also*, http://www.epa.gov/air/urbanair/so2/what1.html.

[11] *See*, http://www.epa.gov/interstateairquality/basic.html#basic.

[12] "Circulating dry scrubber" can get more than 90% removal; and wet scrubbers can achieve up to 99 percent. *See* http://www.icac.com/. http://www.icac.com/i4a/pages/index.cfm?pageid=3401

[13] *National Energy Policy Report of the National Energy Policy Development Group*, May, 2001, page 3-4.

[14] *See*, Informed Regulatory Decision – 2004 Draft Report to Congress on the Costs and Benefits of Federal Regulations and Unfunded Mandates on State, Local, and Tribal Entities, available at:
www.whitehouse.gov/omb/inforeg/draft_2004_cbreport.pdf).

[15] *See*, http://www.epa.gov/air/urbanair/nox/what.html.

[16] *See*, http://www.epa.gov/air/urbanair/nox/hlth.html.

[17] Plant upgrades and retrofits are ongoing. *Power* magazine, "W.A. Parish Electric Generation Station, Thompson, Texas," (July/August 2004) recently described modifications made to the W.A. Parish burners. Units 5 and 6, which

have NOx emission rates below 0.10 lbs/MMBtu, appear to have duel-fuel (gas/coal) burners. Units 7 and 8, which have emissions rates of roughly 0.15 lbs/MMBtu, appear to be 100 percent coal-fired.

[18] *See*, http://www.epa.gov/airmarkets/fednox/126noda2/pegasus.pdf

[19] *See*, http://www.epa.gov/mercury/about.htm.

[20] *Second National Report on Human Exposure to Environmental Chemicals*, Department of Health and Human Services, Centers for Disease Control and Prevention, National Center for Environmental Health, Division of Laboratory Sciences, Atlanta, Georgia, NCEH Pub. No. 02-0716, January 2003; available at: http://www.cdc.gov/exposurereport/.

[21] *The Impact of Federal Clean Air Rules on Mercury Emissions at U.S. Coal-Fired Power Plants*, July 2006, available at: http://www.nwf.org/mercury .

[22] Energy Information Administration, *Electric Power Monthly for April 2005* (with 2004 year-end data), DOE/EIA-0226 (2005/04), available at: http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html

Appendix A. All Plants ≥ 2 Million MWh, by State (2006)

Source: U.S. Department of Energy, Energy Information Administration (EIA) EIA-906/EIA-920 Monthly Time Series, Fourth Quarter 2006 (December)

Facility Name	State	County	Facility Owner	Primary Fuels	Total Net Generation (MWh)
Barry	AL	Mobile	Southern Company- Alabama Power Company	DFO/BIT/NG	14,639,481
Gorgas	AL	Walker	Southern Power- Alabama Power Co	DFO/BIT	8,320,379
Greene County	AL	Greene	Alabama Power Co	DFO/BIT/NG/SC	3,987,948
E C Gaston	AL	Shelby	Southern Company- Alabama Power Company	DFO/BIT	11,389,703
Colbert	AL	Colbert	Tennessee Valley Authority	DFO/BIT/NG	7,676,882
Widows Creek	AL	Jackson	Tennessee Valley Authority	DFO/BIT	9,644,414
Charles R Lowman	AL	Washington	Alabama Electric Coop Inc	DFO/BIT	3,834,124
James H Miller Jr	AL	Jefferson	Southern Company- Alabama Power Company	DFO/SUB/NG	21,658,406
Plant H. Allen Franklin	AL	Lee	Southern Power Co	NG	2,701,133
E B Harris Generating Plant	AL	Autauga	Southern Power Co	NG	2,433,545
Morgan Energy Center	AL	Limestone	Calpine Operating Services Company Inc	NG	2,286,091
White Bluff	AR	Jefferson	Entergy Arkansas Inc- Arkansas Power & Light	DFO/SUB	9,654,935
Flint Creek Power Plant	AR	Benton	Southwestern Electric Power Co	DFO/SUB	3,684,025
Independence	AR	Independence	Entergy Arkansas Inc- Arkansas Power & Light	DFO/SUB	10,781,357
Union Power Station	AR	Union	Union Power Partners LP	NG	4,464,749
Cholla	AZ	Navajo	Arizona Public Service Co	DFO/SUB/NG	7,529,088
APS West Phoenix Power Plant	AZ	Maricopa	Arizona Public Service Co	NG	2,057,981
Apache Station	AZ	Cochise	Arizona Electric Pwr Coop Inc	DFO/SUB/NG	2,843,773
Navajo Generating Station	AZ	Coconino	Salt River Proj Ag I & P Dist	DFO/BIT	17,538,831
Coronado Generating Station	AZ	Apache	Salt River Proj Ag I & P Dist	DFO/SUB	5,888,365
Santan	AZ	Maricopa	Salt River Proj Ag I & P Dist	NG	3,095,038
Springerville Generating Station	AZ	Apache	Tucson Electric Power Co	DFO/SUB/SUN	5,801,431
South Point Energy Center, LLC	AZ	Mohave	South Point Energy Center LLC	NG	2,400,459
Gila River Power Station	AZ	Maricopa	Panda Gila River LP	NG	5,559,314
Redhawk Generating Facility	AZ	Maricopa	Arizona Public Service Co	NG	4,915,675
Mesquite Generating Station	AZ	Maricopa	Mesquite Power LLC	NG	7,048,652
Moss Landing	CA	Monterey	Wood Group Power Operations- Moss Landing	NG	6,308,443
Mountainview Power Company, LLC	CA	San Bernadino	Mountainview Power Company, LLC	NG	4,866,120
Haynes Generating Station	CA	Los Angeles	Los Angeles City of	DFO/NG	3,481,806
Valley Gen Station	CA	Los Angeles	Los Angeles City of	DFO/NG	2,200,596
Calpine Sutter Energy Center	CA	Sutter	Calpine Corp-Sutter	NG	2,103,327
La Paloma Generating Plant	CA	Kern	La Paloma Generating Co LLC	NG	5,425,497
Sunrise Power Company	CA	Kern	Sunrise Power Co LLC	NG	3,568,474
Los Medanos Energy Center, LLC	CA	Contra Costa	Los Medanos Energy Center LLC	NG	2,935,701
Delta Energy Center, LLC	CA	Kern	Delta Energy Center LLC	NG	4,834,349
Metcalf Energy Center	CA	Santa Clara	Calpine Corp	NG	2,370,154
Elk Hills Power	CA	Kern	Elk Hills Power LLC	NG	3,456,224
High Desert Power Project	CA	Bernardino	High Desert Power Project LLC	NG	3,926,682
Pastoria Energy Facility	CA	Kern	Calpine Corp	NG	4,649,165

Appendix A. All Plants ≥ 2 Million MWh, by State (2006)

Facility Name	State	County	Facility Owner	Primary Fuels	Total Net Generation (MWh)
Cosumnes Power Plant	CA	Sacramento	Sacramento Municipal Util Dist	NG	2,485,381
Palomar Energy	CA	San Diego	San Diego Gas & Electric Co	NG	2,475,090
Cherokee	CO	Adams	Public Service Co of Colorado	DFO/SUB/BIT/NG	4,782,832
Comanche (470)	CO	Pueblo	Public Service Co of Colorado	DFO/SUB/NG	4,877,931
Hayden	CO	Routt	Public Service Co of Colorado	PG/WDS	3,502,621
Craig	CO	Moffat	Tri-State G & T Assn Inc	DFO/NG/SUB	9,751,359
Fort St. Vrain	CO	Weld	Public Service Co of Colorado	NG	4,218,479
Pawnee	CO	Morgan	Public Service Co of Colorado	DFO/SUB/NG	3,765,345
Rawhide Energy Station	CO	Larimer	Platte River Power Authority	DFO/SUB/NG	2,210,393
Front Range Power Plant	CO	Boulder	Colorado Springs City of	NG	2,215,262
Rocky Mountain Energy Center	CO	Weld	Rocky Mountain Energy Ctr LLC	NG	2,899,884
Bridgeport Harbor Station	CT	Fairfield	PSEG Power Connecticut LLC	NG/OG	2,856,649
Bridgeport Energy	CT	Fairfield	Bridgeport Energy LLC	NG	2,393,165
Milford Power Company LLC	CT	New Haven	Milford Power Co LLC	DFO/NG	2,957,856
Lake Road Generating Company	CT	Windam	Lake Road Generating Co LP	DFO/NG	3,917,501
Indian River	DE	Sussex	Indian River Operations Inc	DFO/BIT/SUB	3,384,312
Seminole (136)	FL	Putnam	Seminole Electric Coop Inc	DFO/BIT/PC/SC	9,495,696
St. Johns River Power	FL	Duval	JEA	DFO/BIT/PC/SC	9,343,278
Curtis H. Stanton Energy Center	FL	Orange	Orlando Utilities Comm	DFO/BIT/RFO/LFG	6,423,073
Cape Canaveral	FL	Brevard	Progress Energy Florida	NG/RFO	2,025,417
Fort Myers	FL	Lee	Florida Power & Light Company	DFO/NG/RFO	10,121,263
Lauderdale	FL	Broward	Progress Energy Florida	DFO/NG	5,898,224
Port Everglades	FL	Broward	Progress Energy Florida	DFO/NG/RFO	3,218,498
Sanford	FL	Volusia	Florida Power & Light Company	NG/RFO	11,999,363
Turkey Point	FL	Dade	Florida Power & Light Company	DFO/NG/RFO/NUC	13,359,426
Crystal River	FL	Citrus	Progress Energy Florida Inc.	DFO/BIT/NUC	21,968,604
Crist Electric Generating Plant	FL	Escambia	Gulf Power Co	DFO/BIT/NG/WDS	6,279,191
Lansing Smith Generating Plant	FL	Bay	Gulf Power Co	DFO/BIT/NG	4,706,050
Big Bend	FL	Hillsborough	Tampa Electric Company	DFO/BIT/PC	9,422,708
Northside	FL	Duval	JEA	DFO/BIT/NG/PC/RFO/LFG	4,491,183
C D McIntosh Jr Power Plant	FL	Polk	Lakeland (City of)	DFO/SUB/NG	3,610,806
Manatee	FL	Manatee	Florida Power & Light Company	DFO/NG/RFO	10,870,909
Martin	FL	Martin	Florida Power & Light Company	DFO/NG/RFO	17,030,225
Hines Energy Complex	FL	Polk	Progress Energy Florida Inc	DFO/NG	7,154,180
Payne Creek Generating Station	FL	Hardee	Seminole Electric Coop Inc	DFO/NG	2,109,280
Bayside Power Station	FL	Hillsborough	Tampa Electric Co	NG	6,970,591
Anclote	FL	Pasco	Progress Energy Florida Inc	DFO/NG/RFO	2,940,530
Stanton A	FL	Orange	Southern Power Co	DFO/NG	2,786,840
Bowen	GA	Bartow	Georgia Power Co	DFO/BIT	22,631,283
Hammond	GA	Floyd	Georgia Power Co	DFO/BIT	4,007,384
Harllee Branch	GA	Putnam	Georgia Power Co	DFO/BIT	10,247,285
Jack McDonough	GA	Cobb	Georgia Power Co	DFO/SUB/BIT	3,772,302
Yates	GA	Coweta	Southern Company-Georgia Power	DFO/BIT/NG	6,977,562

Appendix A. All Plants ≥ 2 Million MWh, by State (2006)

Facility Name	State	County	Facility Owner	Primary Fuels	Total Net Generation (MWh)
			Company		
Wansley (6052)	GA	Heard	Southern Power- Georgia Power	DFO/BIT	12,617,286
Scherer	GA	Monroe	Southern Company-Georgia Power Company	DFO/SUB	23,150,235
McIntosh Combined Cycle Facility	GA	Effingham	Savannah Electric & Power Co	DFO/NG	5,081,201
Council Bluffs	IA	Pottawatomie	MidAmerican Energy Co	DFO/SUB/NG	5,234,432
George Neal North	IA	Woodbury	MidAmerican Energy Co	SUB/NG	6,349,011
Ottumwa	IA	Wapello	Interstate Power and Light Co	DFO/SUB	3,952,075
Louisa	IA	Louisa	MidAmerican Energy Co	DFO/SUB/NG	4,467,331
George Neal South	IA	Woodbury	MidAmerican Energy Co	DFO/SUB	4,521,837
Joliet 29	IL	Will	Midwest Generations EME LLC	SUB/NG	5,517,319
E D Edwards	IL	Peoria	Ameren Energy Resources Generating Co.	DFO/SUB/BIT	4,442,708
Coffeen	IL	Montgomery	Ameren Energy Generating Co	DFO/SUB/BIT	5,801,387
Crawford	IL	Cook	Midwest Generations EME LLC	NG/SUB	2,851,637
Kincaid Station	IL	Christian	Dominion Energy Services Co	SUB/NG	5,375,239
Powerton	IL	Tazewell	Midwest Generations EME LLC	SUB/NG	7,642,897
Waukegan	IL	Lake	Midwest Generations EME LLC	DFO/SUB/NG	4,115,977
Will County	IL	Will	Midwest Generations EME LLC	DFO/SUB	5,614,000
Joppa Steam	IL	Massac	Electric Energy Inc	DFO/SUB/NG	8,349,924
Baldwin Energy Complex	IL	Randolph	Dynegy Midwest Generation Inc	DFO/SUB/OTH/TDF	12,645,402
Havana	IL	Mason	Dynegy Midwest Generation Inc	DFO/SUB/NG/RFO	2,427,926
Hennepin Power Station	IL	Putnam	Dynegy Midwest Generation Inc	SUB/NG	2,039,114
Wood River Power Station	IL	Madison	Dynegy Midwest Generation Inc	SUB/NG/PC	3,155,879
Duck Creek	IL	Fulton	Ameren Energy Resources Generating Co.	DFO/BIT	2,212,600
Newton	IL	Jasper	Ameren Energy Generating Co	DFO/SUB	7,179,510
State Line Generating Station (IN)	IN	Lake	State Line Energy LLC	SUB/NG	2,696,781
Clifty Creek	IN	Jefferson	Indiana-Kentucky Electric Corp	DFO/BIT/SUB	9,128,635
Tanners Creek	IN	Dearborn	Indiana Michigan Power Co	DFO/SUB/BIT	5,877,369
Harding Street Station (EW Stout)	IN	Marion	Indianapolis Power & Light Co	DFO/BIT/NG	3,862,890
Petersburg	IN	Pike	Indianapolis Power & Light Co	DFO/BIT	11,218,274
Bailly Generating Station	IN	Porter	Northern Indiana Pub Serv Co	BIT/NG	2,144,456
Michigan City Generating Station	IN	La Porte	Northern Indiana Pub Serv Co	NG/SUB	2,852,261
Cayuga	IN	Vermillion	PSI Energy Inc	DFO/BIT/NG	6,233,855
R Gallagher	IN	Floyd	PSI Energy Inc	DFO/BIT	2,516,769
Wabash River	IN	Vigo	PSI Energy Inc	DFO/BIT/NG	4,250,856
F B Culley Generating Station	IN	Warrick	Southern Indiana Gas & Elec Co	BIT/NG	2,326,502
R M Schahfer	IN	Jasper	Northern Indiana Pub Serv Co	BIT/NG/SUB/PC	9,675,831
Gibson	IN	Gibson	PSI Energy, Inc	DFO/BIT	22,465,906
A B Brown Generating Station	IN	Posey	Southern Indiana Gas & Elec Co	DFO/BIT/NG	3,409,178
Rockport	IN	Spencer	American Electric Power- Indiana Michigan Power	DFO/SUB/BIT	20,356,894
Merom	IN	Sullivan	Hoosier Energy R E C Inc	DFO/BIT	6,470,377
Warrick	IN	Warrick	Alcoa Generating Corp	BIT/NG	4,457,515

Appendix A. All Plants ≥ 2 Million MWh, by State (2006)

Facility Name	State	County	Facility Owner	Primary Fuels	Total Net Generation (MWh)
Holcomb	KS	Finney	Sunflower Electric Power Corp	SUB/NG	2,384,975
La Cygne	KS	Linn	Kansas City Power & Light Co	DFO/BIT/SUB	9,390,258
Lawrence Energy Center	KS	Douglas	Westar Energy	BIT/SUB/NG	3,257,371
Jeffrey Energy Center	KS	Pottawatomie	Westar Energy	DFO/SUB	14,264,089
Big Sandy	KY	Lawrence	Kentucky Power Co	DFO/BIT	7,171,505
E W Brown	KY	Mercer	Kentucky Utilities Co	DFO/BIT/NG	3,805,154
Ghent	KY	Carroll	Kentucky Utilities Company	DFO/BIT	12,207,723
Cane Run	KY	Jefferson	Louisville Gas & Electric Co	DFO/BIT/NG/ SC	3,581,101
Mill Creek	KY	Jefferson	Louisville Gas & Electric Co	BIT/NG	9,804,862
Elmer Smith	KY	Daviess	Owensboro Municipal Utilities	DFO/BIT/PC/ PG/TDF	2,205,772
Paradise	KY	Muhlenberg	Tennessee Valley Authority	DFO/SUB/BIT	14,537,458
Shawnee	KY	McCracken	Tennessee Valley Authority	DFO/BIT	9,507,624
Coleman	KY	Hancock	Western Kentucky Energy Corp	BIT/NG/SC	2,712,034
East Bend	KY	Boone	Cincinnati Gas & Electric Co	DFO/BIT	4,972,870
H L Spurlock	KY	Mason	East Kentucky Power Coop Inc	DFO/BIT	7,610,353
Trimble County	KY	Trimble	Louisville Gas & Electric Co	DFO/BIT/NG/ SC	4,526,798
R D Green	KY	Webster	Western Kentucky Energy Corp	DFO/BIT/PC/ SC	3,702,495
D B Wilson	KY	Ohio	Western Kentucky Energy Corp	DFO/BIT/PC	3,203,633
Dolet Hills Power Station	LA	De Soto	Central Louisiana Electric Co	NG/LIG	4,715,236
Louisiana 1	LA	Lafayette	Entergy Gulf States Inc	NG/OG	2,253,916
R S Nelson	LA	Calcasieu	Entergy Gulf States Inc	DFO/SUB/NG/ PC	6,094,581
Evangeline Power Station (Coughlin)	LA	Lewis	Cleco Evangeline LLC	NG	2,471,066
Nine mile Point	LA	Jefferson	Entergy Louisiana Inc	DFO/NG	4,018,882
Big Cajun 2	LA	Coupee	Louisiana Generating LLC	DFO/SUB	12,817,533
Rodemacher Power Station	LA	Rapides	Central Louisiana Electric Co. Power	DFO/SUB/NG/ RFO	3,749,498
Taft Cogeneration Facility	LA	St. Charles	Occidental Chemical Corporation	NG/OG	4,010,932
R S Cogen	LA	Calcasieu	PPG Industries Inc	NG	3,311,795
Plaquemine Cogen Facility	LA	Iberville	Ohio Power Co	NG/OG	4,196,085
Perryville Power Station	LA	Ouachita	Entergy Louisiana Inc	NG	2,083,265
Mystic	MA	Middlesex	Boston Generating, LLC	DFO/NG/RFO	9,864,112
Brayton Point	MA	Bristol	Dominion Energy New England, LLC	DFO/BIT/NG/ RFO	7,446,775
Salem Harbor	MA	Essex	Dominion Energy New England, LLC	DFO/BIT/RFO	2,309,297
ANP Bellingham Energy Project	MA	Suffolk	ANP Bellingham Energy Co	NG	5,166,877
Fore River Station	MA	Norfolk	Boston Generating LLC	DFO/NG	2,408,866
Brandon Shores	MD	Anne Arundel	Constellation Power Source Gen	DFO/BIT	8,416,948
Herbert A Wagner	MD	Anne Arundel	Constellation Power Source Gen	DFO/BIT/NG/ RFO	2,612,814
Chalk Point	MD	Georges	Mirant Chalk Point LLC	DFO/BIT/NG/ RFO	4,691,534
Dickerson	MD	Montgomery	Mirant Mid-Atlantic LLC	DFO/BIT/NG	3,151,758
Morgantown	MD	Charles	Mirant Mid-Atlantic LLC	DFO/RFO/SC	7,520,144
Maine Independence Station	ME	Cumberland	Casco Bay Energy Co LLC	NG	2,187,905
Westbrook Energy Center	ME	Cumberland	Calpine Eastern Corp	NG	3,219,462
Dan E Karn	MI	Bay	Consumers Energy Co	DFO/SUB/BIT	3,765,886

Appendix A. All Plants ≥ 2 Million MWh, by State (2006)

Facility Name	State	County	Facility Owner	Primary Fuels	Total Net Generation (MWh)
				/NG/RFO	
J H Campbell	MI	Ottawa	Consumers Energy Co	DFO/BIT/SUB	8,392,775
J R Whiting	MI	Monroe	Consumers Energy Co	DFO/BIT/SUB	2,378,504
Monroe	MI	Monroe	Detroit Edison	DFO/SUB/BIT	17,986,630
River Rouge	MI	Wayne	Detroit Edison Co	DFO/BIT/SUB /NG/OG	3,045,465
St. Clair	MI	St. Clair	Detroit Edison Co	DFO/BIT/SUB /NG/RFO	7,439,052
Trenton Channel	MI	Wayne	Detroit Edison Co	DFO/SUB/BIT	4,300,097
Presque Isle	MI	Marquette	Wisconsin Electric Power Co	DFO/BIT/SUB	3,334,963
Belle River	MI	St. Clair	Detroit Edison Co	DFO/SUB/NG	8,484,660
Midland Cogeneration Venture	MI	Midland	Midland Cogeneration Venture	DFO/NG	5,744,605
Boswell Energy Center	MN	Itasca	Minnesota Power Inc	DFO/SUB	7,124,945
Black Dog	MN	Dakota	Northern States Power Co	DFO/SUB/NG	2,089,284
Sherburne County	MN	Sherburne	Northern States Power Company	DFO/SUB	12,872,776
Hawthorn	MO	Jackson	Kansas City Power & Light Co	NG/SUB	4,243,606
Montrose	MO	Henry	Kansas City Power & Light Co	DFO/SUB	3,114,207
Sibley	MO	Jackson	Aquila, Inc.	BIT/SUB/PG/T DF	3,047,029
Labadie	MO	Franklin St. Louis City	Ameren- Union Electric	DFO/SUB	18,577,546
Meramec	MO	City	Union Electric Co	DFO/SUB/NG	5,667,553
Sioux	MO	St. Charles	Union Electric Co	DFO/BIT/PC/ SUB/TDF	6,398,439
New Madrid Power Plant	MO	New Madrid	Associated Electric Coop Inc	DFO/SUB	7,659,009
Thomas Hill Energy Center	MO	Randolph	Associated Electric Coop Inc	DFO/SUB	7,662,061
Iatan	MO	Platte	Kansas City Power & Light Co	DFO/SUB	5,012,391
Rush Island	MO	Jefferson	Union Electric Co	DFO/SUB	8,737,671
Watson Electric Generating Plant	MS	Harrison	Mississippi Power Co	BIT/NG	4,878,069
R D Morrow	MS	Lamar	South Mississippi El Pwr Assn	DFO/BIT	2,636,912
Daniel Electric Generating Plant	MS	Jackson	Mississippi Power Company	DFO/BIT/NG	10,455,005
Red Hills Generation Facility	MS	Choctaw	Choctaw Generating LP	NG/LIG	3,201,074
Attala Generating Plant	MS	Attala	Entergy Mississippi Inc	NG	2,001,040
Colstrip	MT	Rosebud	PP&L Montana	DFO/SUB/WO	14,764,749
Asheville	NC	Buncombe	Progress Energy Carolinas Inc	DFO/BIT/NG	2,407,380
Roxboro	NC	Person	Progress Energy Carolinas Inc	DFO/BIT	15,082,569
L V Sutton	NC	New Hanover	Progress Energy Carolinas Inc	DFO/BIT	2,767,637
G G Allen	NC	Gaston	Duke Energy Corp	DFO/BIT	6,426,453
Cliffside	NC	Cumberland	Duke Energy Corp	DFO/BIT	4,075,250
Marshall	NC	Catawba	Duke Energy Corp	DFO/BIT	12,968,324
Mayo	NC	Person	Progress Energy Carolinas Inc	DFO/BIT	4,375,057
Belews Creek	NC	Stokes	Duke Energy Corp	DFO/BIT	15,491,411
Leland Olds	ND	Mercer	Basin Electric Power Coop	DFO/SUB/LIG	3,904,544
Milton R Young	ND	Oliver	Minnkota Power Coop Inc	DFO/LIG	4,861,874
Coal Creek	ND	Mclean	Great River Energy	DFO/LIG	8,403,311
Antelope Valley	ND	Mercer	Basin Electric Power Coop	DFO/LIG	7,106,993
Coyote	ND	Mercer	Otter Tail Power Co	DFO/LIG	2,844,480
North Omaha Station	NE	Douglas	Omaha Public Power District	SUB/NG	3,476,965

Appendix A. All Plants ≥ 2 Million MWh, by State (2006)

Facility Name	State	County	Facility Owner	Primary Fuels	Total Net Generation (MWh)
Gerald Gentleman Station	NE	Lincoln	Nebraska Public Power District	DFO/SUB/NG	9,422,664
Nebraska City Station	NE	Otoe	Omaha Public Power District	DFO/SUB	4,509,848
Merrimack	NH	Merrimack	Public Service Co of NH	DFO/BIT	3,161,701
Granite Ridge Energy	NH	Rockingham	Granite Ridge Energy LLC	NG	3,204,189
Newington Power Facility	NH	Rockingham	Newington Energy LLC	DFO/NG	2,640,191
Bergen	NJ	Bergen	PSEG Fossil LLC	NG/KER	4,291,361
Hudson Generating Station	NJ	Hudson	PSEG Fossil LLC	BIT/NG/RFO	3,023,550
Mercer Generating Station	NJ	Mercer	PSEG Fossil LLC	BIT/NG/KER	3,029,914
Salem	NJ	Cumberland	PSEG Nuclear LLC, Exelon	DFO/KER/NUC	19,348,967
Linden Cogeneration Facility	NJ	Union	Cogen Technologies Linden Vent	DFO/NG/WO	5,149,428
Four Corners Steam Elec Station	NM	San Juan	Arizona Public Service Company	SUB/NG	15,969,176
San Juan	NM	San Juan	Public Service Company of New Mexico	DFO/SUB	12,466,870
Reid Gardner	NV	Clark	Nevada Power Co	DFO/BIT	2,899,640
North Valmy	NV	Humboldt	Sierra Pacific Power Co	DFO/BIT	3,550,925
El Dorado Energy	NV	Clark	El Dorado Energy LLC	NG	3,533,824
REI Bighorn	NV	Clark	Reliant Energy Wholesale Generation LLC	NG	2,147,232
Silverhawk	NV	Clark	Nevada Power Co	NG	2,178,338
Dynegy Danskammer	NY	Orange	Dynegy Northeast Gen Inc	DFO/BIT/NG/RFO	2,279,185
East River	NY	New York	Consolidated Edison Co-NY Inc	NG/RFO	2,781,565
Ravenswood Generating Station	NY	Queens	KeySpan-Ravenswood Inc	NG/RFO	2,746,067
Northport	NY	Suffolk	KeySpan Generation LLC	DFO/NG/RFO	5,918,205
AES Cayuga (Milliken)	NY	Tompkins	AES Cayuga LLC	DFO/BIT	2,275,347
Huntley Power	NY	Erie	NRG Huntley Operations Inc	DFO/BIT/SUB	2,666,529
Dunkirk	NY	Chautauqua	Dunkirk Power LLC	DFO/BIT/SUB	3,272,455
AES Somerset (Kintigh)	NY	Niagara	AES Somerset LLC	DFO/BIT/PC	5,398,183
Astoria Generating Station	NY	Queens	U S Power Generating Company LLC	NG/RFO	2,486,683
Saranac Cogeneration	NY	Clinton	Saranac Power Partners LP	NG	2,047,195
Brooklyn Navy Yard Cogeneration	NY	Kings	Brooklyn Navy Yard Cogen PLP	NG	2,031,657
Athens Generating Company	NY	Greene	Athens Generating Company LLC	DFO/NG	4,384,439
Poletti 500 MW CC	NY	Queens	Power Authority of State of NY	DFO/NG	3,054,614
Cardinal	OH	Jefferson	Cardinal Operating Co.	DFO/BIT	11,490,833
Walter C Beckjord Generating Station	OH	Clermont	Duke Energy- Cincinnati Gas & Electric Co	DFO/BIT	6,149,996
Miami Fort Generating Station	OH	Hamilton	Duke Energy- Cincinnati Gas & Electric Co	DFO/BIT	6,658,669
Avon Lake Power Plant	OH	Lorain	Orion Power Midwest LP	DFO/BIT/NG	3,548,783
Eastlake	OH	Lake	FirstEnergy Generation Corp	DFO/SUB	8,764,959
Conesville	OH	Coshocton	Columbus Southern Power Co	DFO/BIT	9,052,577
J M Stuart	OH	Adams	Dayton Power & Light Co	DFO/BIT/SC	14,694,109
W H Sammis	OH	Jefferson	FirstEnergy Generation Corp	DFO/BIT	15,594,452
Muskingum River	OH	Washington	AEP- Ohio Power Co	DFO/BIT	7,503,925
Kyger Creek	OH	Gallia	Ohio Valley Electric Corp	DFO/BIT/SUB	7,340,708
Bay Shore	OH	Lucas	FirstEnergy Generation Corp	DFO/SUB/PC	4,407,217
W H Zimmer Generating Station	OH	Clermont	Cincinnati Gas & Electric Co	DFO/BIT	9,587,562

Appendix A. All Plants ≥ 2 Million MWh, by State (2006)

Facility Name	State	County	Facility Owner	Primary Fuels	Total Net Generation (MWh)
Killen Station	OH	Adams	Dayton Power & Light Co	DFO/BIT/SC	4,160,718
Gen J M Gavin	OH	Gallia	Ohio Power	DFO/BIT	16,671,669
Grand River Dam Authority	OK	Mayes	Grand River Dam Authority	DFO/SUB/NG	6,151,201
Muskogee	OK	Muskogee	Oklahoma Gas & Electric Co	NG/SUB	10,385,761
Seminole (2956)	OK	Seminole	Oklahoma Gas & Electric Co	NG/RFO	3,098,755
Northeastern	OK	Rogers	Public Service Co of Oklahoma	DFO/NG/SUB	9,856,633
Riverside (4940)	OK	Rockford	Public Service Co of Oklahoma	DFO/NG	2,346,399
Sooner	OK	Noble	Oklahoma Gas & Electric Co	DFO/SUB	6,288,120
Hugo	OK	Choctaw	Western Farmers Elec Coop Inc	DFO/SUB	2,917,077
Green Country Energy, LLC	OK	Tulsa	Green Country OP Services LLC	NG	2,701,435
McClain Energy Facility	OK	McClain	Oklahoma Gas & Electric Co	NG	3,084,116
Redbud Power Plant	OK	Randolph	InterGen North America	NG	3,059,740
Tenaska Kiamichi Generating Station	OK	Pittsburg	Kiowa Power Partners LLC	NG	5,736,858
Boardman	OR	Morrow	Portland General Electric Co	DFO/SUB	2,373,754
Hermiston	OR	Umatilla	Hermiston Generating Co LP	NG	3,069,321
Hermiston Power Plant	OR	Umatilla	Hermiston Power Partnership	NG	2,905,519
Elrama	PA	Allegheny	Orion Power Midwest LP	BIT/DFO	2,151,894
Portland	PA	Northhampton	Reliant Energy Mid-Atlantic PH LLC	DFO/BIT/NG	2,168,315
Conemaugh	PA	Indiana	Reliant Engy NE Management Co	DFO/BIT/NG/SC	14,290,006
Homer City	PA	Indiana	Midwest Generations EME LLC	DFO/BIT	12,255,226
Seward	PA	Indiana	Reliant Energy Seward LLC	DFO/WC	3,251,213
Shawville	PA	Clearfield	Reliant Energy Mid-Atlantic PH LLC	DFO/BIT	3,508,513
Keystone	PA	Armstrong	Reliant Engy NE Management Co	DFO/BIT/SC	12,727,533
Brunner Island	PA	York	PPL Brunner Island LLC	DFO/BIT/SC	9,132,954
Montour	PA	Montour	PPL Montour LLC	DFO/BIT/SC	10,916,977
Eddystone Generating Station	PA	Delaware	Exelon Generation Co LLC	DFO/BIT/NG/RFO	2,886,159
Hatfields Ferry Power Station	PA	Greene	Allegheny Energy Supply Co LLC	DFO/BIT/NG	9,345,925
Bruce Mansfield	PA	Beaver	First Energy Company- Pennsylvania Power	DFO/BIT/PC	18,628,146
Cheswick	PA	Allegheny	Orion Power Midwest LP	DFO/BIT/NG	2,814,375
Fairless Energy, LLC	PA	Bucks	Fairless Energy LLC	NG/OG	2,679,881
Marcus Hook, LP	PA	Delaware	FPL Energy Marcus Hook LP	NG	2,188,845
Rhode Island State	RI	Providence	FPL Energy Operating Serv Inc	NG	2,764,997
Cross	SC	Berkeley	South Carolina Pub Serv Auth	DFO/BIT/PC/SC	8,576,427
H B Robinson	SC	Darlington	Progress Energy Carolinas Inc	DFO/BIT/NG/NUC	7,654,875
Canadys Steam	SC	Colleton	South Carolina Electric&Gas Co	DFO/BIT/NG	2,474,373
Wateree	SC	Richland	South Carolina Electric&Gas Co	DFO/BIT	4,287,153
Williams	SC	Berkeley	South Carolina Genertg Co Inc	DFO/BIT/NG	4,491,471
Jefferies	SC	Berkeley	South Carolina Pub Serv Auth	DFO/BIT/RFO/WAT	2,199,016
Winyah	SC	Georgetown	South Carolina Pub Serv Auth	DFO/BIT/SC	7,994,258
Cope Station	SC	Orangeberg	South Carolina Electric&Gas Co	DFO/BIT/NG	3,426,837
John S. Rainey	SC	Anderson	South Carolina Pub Serv Auth	DFO/NG	2,007,794
Big Stone	SD	Grant	Otter Tail Power Co	DFO/SUB/TDF	3,174,012
Allen	TN	Shelby	Tennessee Valley Authority	DFO/SUB/NG	5,301,265

Appendix A. All Plants ≥ 2 Million MWh, by State (2006)

Facility Name	State	County	Facility Owner	Primary Fuels	Total Net Generation (MWh)
Bull Run	TN	Anderson	Tennessee Valley Authority	DFO/BIT	4,696,141
Cumberland	TN	Stewart	Tennessee Valley Authority	DFO/BIT	18,743,383
Gallatin	TN	Sumner	Tennessee Valley Authority	DFO/SUB/NG	7,609,787
John Sevier	TN	Hawkins	Tennessee Valley Authority	DFO/BIT	5,043,577
Johnsonville	TN	Humphreys	Tennessee Valley Authority	DFO/BIT/NG	7,657,037
Kingston	TN	Roane	Tennessee Valley Authority	DFO/BIT	10,377,572
Oklaunion Power Station	TX	Wilbarger	Public Service Co of Oklahoma	DFO/SUB	3,964,478
Limestone	TX	Limestone	NRG Texas LLC	DFO/SUB/NG/ LIG/PC	12,709,534
Sabine	TX	Orange	Entergy Gulf States Inc	DFO/NG	4,385,581
Cedar Bayou	TX	Chambers	NRG Texas LLC	NG	2,793,442
W A Parish	TX	Fort Bend	NRG Energy	DFO/SUB/NG	20,178,794
Jones Station	TX	Lubbock	Southwestern Public Service Co	DFO/NG	2,357,769
Big Brown	TX	Freestone	TXU	SUB/NG/LIG	8,911,676
Gibbons Creek Steam Electric Station	TX	Grimes	Texas Municipal Power Agency	SUB/NG/PC/L IG	3,611,068
Welsh Power Plant	TX	Titus	Southwestern Electric Power Co	DFO/SUB	10,035,850
Martin Lake	TX	Rusk	TXU	DFO/SUB/BIT /LIG	17,821,177
Monticello	TX	Titus	TXU	DFO/SUB/BIT /LIG	14,961,282
Coleto Creek	TX	Goliad	ANP-Coleto Creek	SUB	5,240,154
Sam Seymour	TX	Fayette	Lower Colorado River Authority	DFO/SUB	10,000,368
J T Deely	TX	Bexar	San Antonio Public Service Bd	DFO/SUB/NG	5,502,734
San Miguel	TX	Atascosa	San Miguel Electric Coop Inc	DFO/LIG	2,937,194
Harrington Station	TX	Potter	Southwestern Public Service Co	SUB/NG	7,623,174
Tolk Station	TX	Lamb	Southwestern Public Service Co	SUB/NG	7,342,494
Sandow	TX	Milam	TXU Generation Co LP	DFO/LIG	3,878,580
Twin Oaks Power, LP	TX	Roberston	Altura Power	NG/LIG	2,351,664
J K Spruce	TX	Bexar	San Antonio Public Service Bd	BIT/SUB/NG	4,040,787
H W Pirkey Power Plant	TX	Harrison	Southwestern Electric Power Co	NG/LIG	4,501,460
Exxonmobil Beaumont Refinery	TX	Jefferson	ExxonMobil Corp	NG/OG	4,039,672
Cogen Lyondell, Inc.	TX	Harris	Cogen Lyondell, Inc.	NG	2,765,563
Sweeny Cogeneration Facility	TX	Brazoria	Sweeny Cogeneration LP	NG/OG	3,333,407
Pasadena Power Plant	TX	Harris	Pasadena Cogneration LP	NG	2,541,752
Tenaska Frontier	TX	Rusk	Tenaska Frontier Partners Ltd	DFO/NG	4,143,008
Mustang Station	TX	Yoakum	Denver City Energy Assoc LP	NG	2,410,483
Gregory Power Facility	TX	San Patricio	DPS Gregory LLC	NG	2,706,019
Midlothian Energy	TX	Ellis	IPA Operations Inc	NG	7,057,168
Lamar Power (Paris)	TX	Lamar	Lamar Power Partners LP	NG	4,508,439
Frontera Generation Facility	TX	Hildalgo	Frontera Generation Limited Partnership	NG	2,036,942
Tenaska Gateway	TX	Rusk	Tenaska Gateway Partners Ltd	DFO/NG	4,139,359
Rio Nogales Power Project, LP	TX	Guadalupe	Tenaska Frontier Partners Ltd	NG	3,902,576
Wolf Hollow I, LP	TX	Hood	Wolf Hollow I L P	NG	3,830,804
Hays Energy Project	TX	Hays	ANP Operations Co - Hays	NG	4,300,004
Guadalupe Generating Station	TX	Guadalupe	Guadalupe Power Partners LP	NG	4,436,855
Lost Pines 1	TX	Bastrop	Lower Colorado River Authority	NG	3,452,313
Eastman	TX	Harrison	Eastman Cogeneration LP	NG/OG	2,113,552

Appendix A. All Plants ≥ 2 Million MWh, by State (2006)

Facility Name	State	County	Facility Owner	Primary Fuels	Total Net Generation (MWh)
Reliant Channelview	TX	Harris	Reliant Energy Channelview LP	NG	5,229,168
Odessa-Ector	TX	Ector	Odessa-Ector Power Partners LP	NG	4,977,708
Freestone Power Generation	TX	Freestone	Freestone Power Generation LP	NG	3,169,555
Jack County Generation Facility	TX	Jack	Brazos Electric Power Coop Inc	NG	3,063,108
Channel Energy Center	TX	Harris	Channel Energy Center	NG/OG	2,840,247
Wise County Power Company	TX	Wise	Wise County Power Co., LP	NG	3,123,527
Baytown Energy Center	TX	Chambers	Calpine Central LP	NG	4,082,048
Cottonwood Energy Project	TX	Newton	Cottonwood Energy Co LP	NG	2,416,715
Deer Park Energy Center	TX	Harris	Deer Park Energy Center	NG	5,464,269
South Houston Green Power	TX	Galveston	South Houston Green Power LP	NG/OG	2,246,864
FPLE Forney, LP	TX	Kaufman	FPLE Forney LP	NG	8,237,423
Hunter	UT	Emery	PacifiCorp	DFO/BIT	9,896,224
Intermountain	UT	Millard	Los Angeles (City of)	SUB/BIT	14,451,689
Bonanza	UT	Uintah	Deseret Generation & Tran Coop	DFO/BIT	3,895,543
Huntington	UT	Emery	PacifiCorp	DFO/BIT	6,139,007
Clinch River	VA	Russell	Appalachian Power Co	BIT/DFO	4,120,888
Chesterfield Power Station	VA	Chesterfield	Dominion Virginia Power	DFO/BIT/NG	8,342,370
Chesapeake Energy Center	VA	Chesapeake	Dominion Virginia Power	DFO/BIT/NG	3,679,845
Yorktown Power Station	VA	York	Dominion Virginia Power	DFO/BIT/NG/ RFO	2,184,050
Clover Power Station	VA	Halifax	Dominion Virginia Power	DFO/BIT	6,942,867
Centralia	WA	Lewis	TransAlta Centralia Gen LLC	DFO/SUB/NG	6,214,950
South Oak Creek	WI	Milwaukee	Wisconsin Electric Power Co	SUB/NG	5,864,385
Edgewater (4050)	WI	Sheboygan	Wisconsin Power & Light Co	DFO/SUB/TD F	4,281,210
Pulliam	WI	Brown	Wisconsin Public Service Corp	DFO/SUB/NG	2,362,947
Weston	WI	Marathon	Wisconsin Public Service Corp	DFO/SUB/NG	3,415,522
Genoa	WI	Vernon	Dairyland Power Coop	DFO/BIT/SUB	2,426,596
J P Madgett	WI	Buffalo	Dairyland Power Coop	DFO/SUB	2,377,632
Pleasant Prairie	WI	Kenosha	Wisconsin Electric Power Co	DFO/SUB/NG	7,523,070
Columbia	WI	Columbia	Wisconsin Power & Light Co	DFO/SUB	6,749,033
John E Amos	WV	Putnam	Appalachian Power Co	DFO/BIT	20,083,907
Phil Sporn	WV	Mason	Appalachian Power Co	DFO/BIT	5,066,133
Fort Martin Power Station	WV	Monongalia	Allegheny Energy Supply Co LLC	DFO/BIT	8,038,844
Harrison Power Station	WV	Harrison	Allegheny Energy Supply Co LLC	DFO/BIT/NG	13,773,139
Kammer	WV	Marshall	Ohio Power Co	DFO/BIT	3,455,847
Mitchell (WV)	WV	Marshall	American Electric Power	DFO/BIT	7,609,049
Mount Storm Power Station	WV	Grant	Dominion Virginia Power	DFO/BIT	11,818,477
Pleasants Power Station	WV	Pleasants	Allegheny Energy Supply Co LLC	DFO/BIT/NG	8,654,920
Mountaineer (1301)	WV	Mason	Appalachian Power Co	DFO/SUB/BIT	7,173,682
Dave Johnston	WY	Converse	PacifiCorp	DFO/SUB	5,776,835
Naughton	WY	Lincoln	PacifiCorp	SUB/NG	4,929,916
Wyodak	WY	Campbell	PacifiCorp	DFO/SUB	2,353,507
Laramie River	WY	Platte	Basin Electric Power Coop	DFO/SUB	12,777,567
Jim Bridger	WY	Sweetwater	Pacificorp	DFO/SUB	15,053,852

Appendix A. All Plants ≥ 2 Million MWh, by State (2006)

Facility Name	State	County	Facility Owner	Primary Fuels	Total Net Generation (MWh)

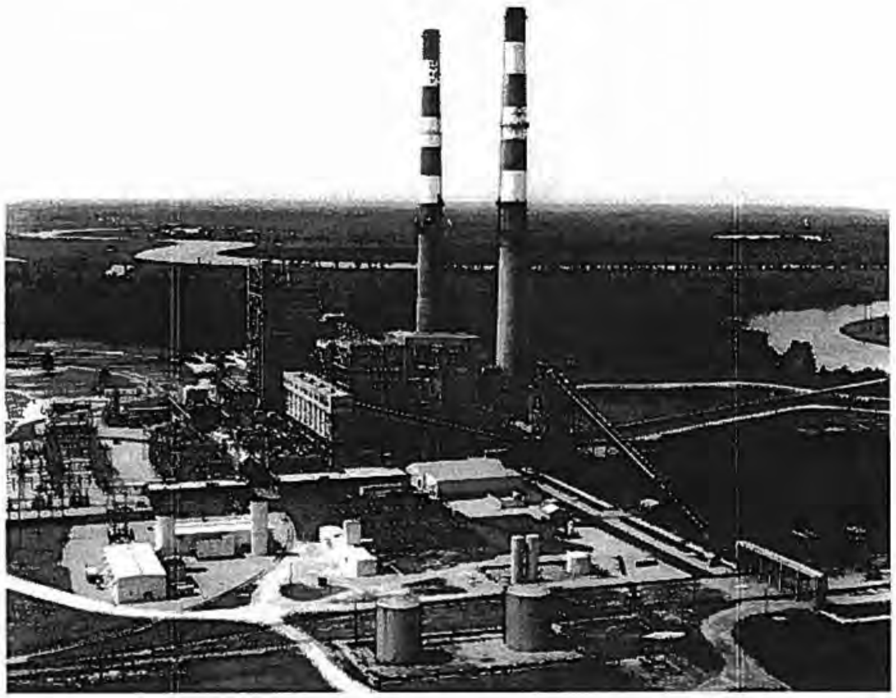
FUEL DATA:

BIT	Anthracite Coal and Bituminous Coal
LIG	Lignite Coal
SUB	Sub-bituminous Coal
WC	Waste/Other Coal (includes anthracite culm, bituminous gob, fine coal, lignite waste, waste coal)
SC	Coal-based Synfuel, including briquettes, pellets, or extrusions, which are formed by binding materials or processes that recycle materials
DFO	Distillate Fuel Oil (Diesel, No. 1, No. 2, and No. 4 Fuel Oils)
PC	Petroleum Coke
RFO	Residual Fuel Oil (No. 5, No. 6 Fuel Oils, and Bunker C Fuel Oil)
WO	Waste/Other Oil (including Crude Oil, Liquid Butane, Liquid Propane, Oil Waste, Re-Refined Motor Oil, Sludge Oil, Tar Oil, or other petroleum-based liquid wastes)
NG	Natural Gas
NUC	Nuclear Fission (Uranium, Plutonium, Thorium)
OTH	Other

APPENDIX B

U.S. Department of Energy National Energy Technology Laboratory publication
SOURCE: http://www.netl.doe.gov/

Tracking New Coal-Fired Power Plants



Coal's Resurgence in Electric Power Generation

NETL

January 24, 2007

Tracking New Coal-Fired Power Plants

This information package is intended to provide an overview of "Coal's Resurgence in Electric Power Generation" by examining proposed new coal-fired power plants that are under consideration. The results contained in this package are derived from information that is available from various tracking organizations and news groups. Although comprehensive, this information is not intended to represent every possible plant under consideration but is intended to illustrate the large potential that exists for new coal-fired power plants.

Proposals to build new power plants are often speculative and typically operate on "boom & bust" cycles, based upon the ever changing economic climate of power generation markets. As such, it should be noted that many of the proposed plants will not likely be built. For example, out of a total portfolio (gas, coal, etc) of 500 GW of newly planned power plant capacity announced in 2001, 91 GW have been already been scrapped or delayed[1].

The Department of Energy does not guarantee the accuracy or suitability of this information.

Sources: 1 - Energy Central Daily & Wall Street Journal

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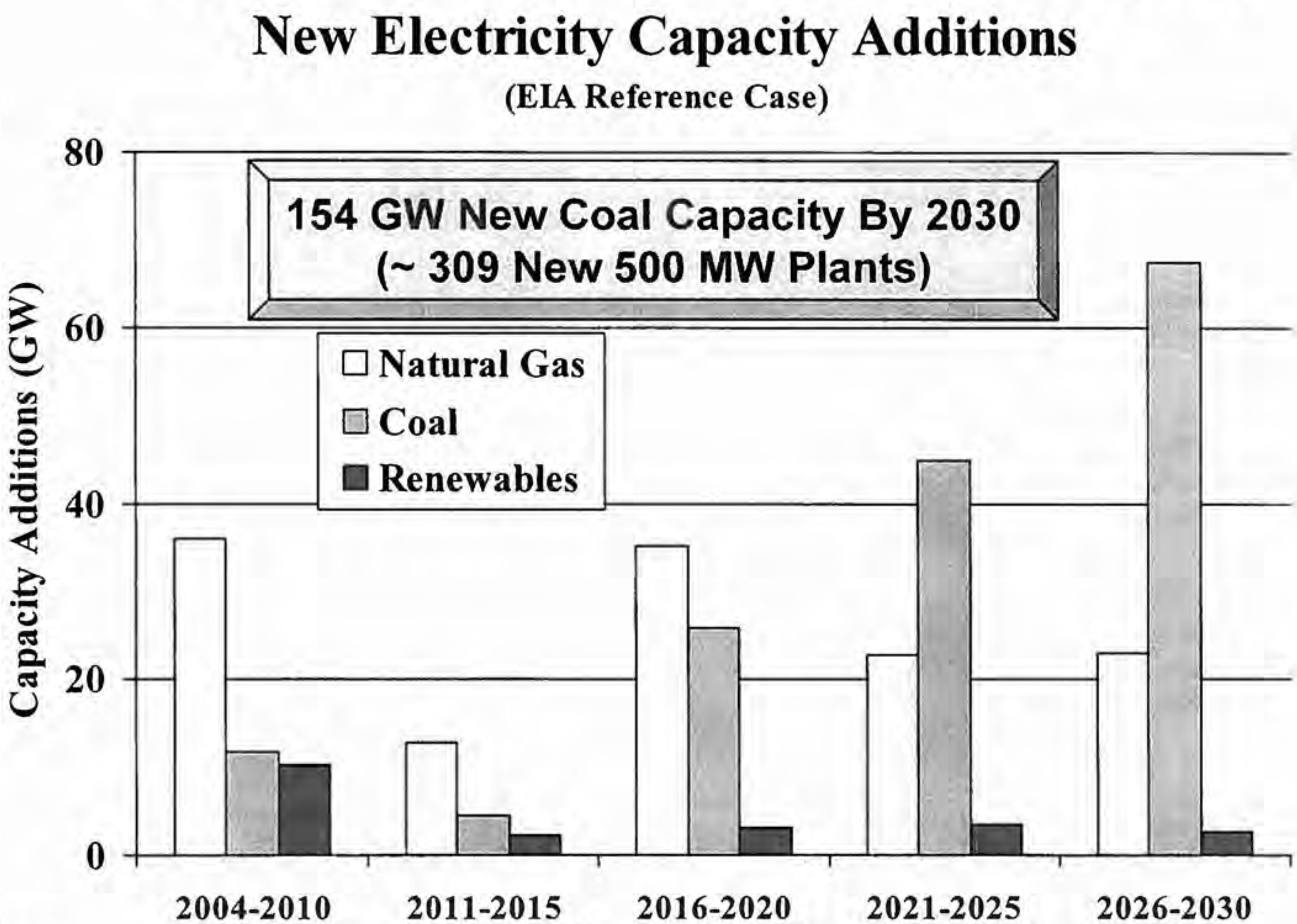
154 GW New Coal Capacity By 2030

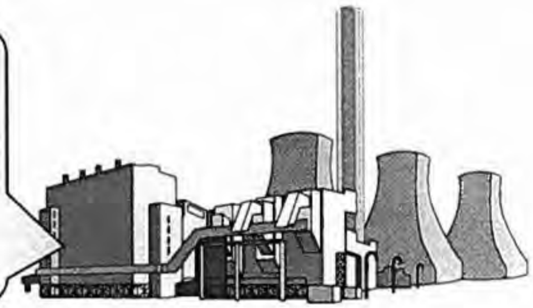
(Accounts for 51% of New Capacity Additions)



Source: Data Derived From EIA Annual Energy Outlook 2006

Coal's Resurgence in Electric Power Generation

159 Proposed & New Plants
96 GW Power
$ 141 Billion Investment



Equivalent Power
for
96 Million Homes

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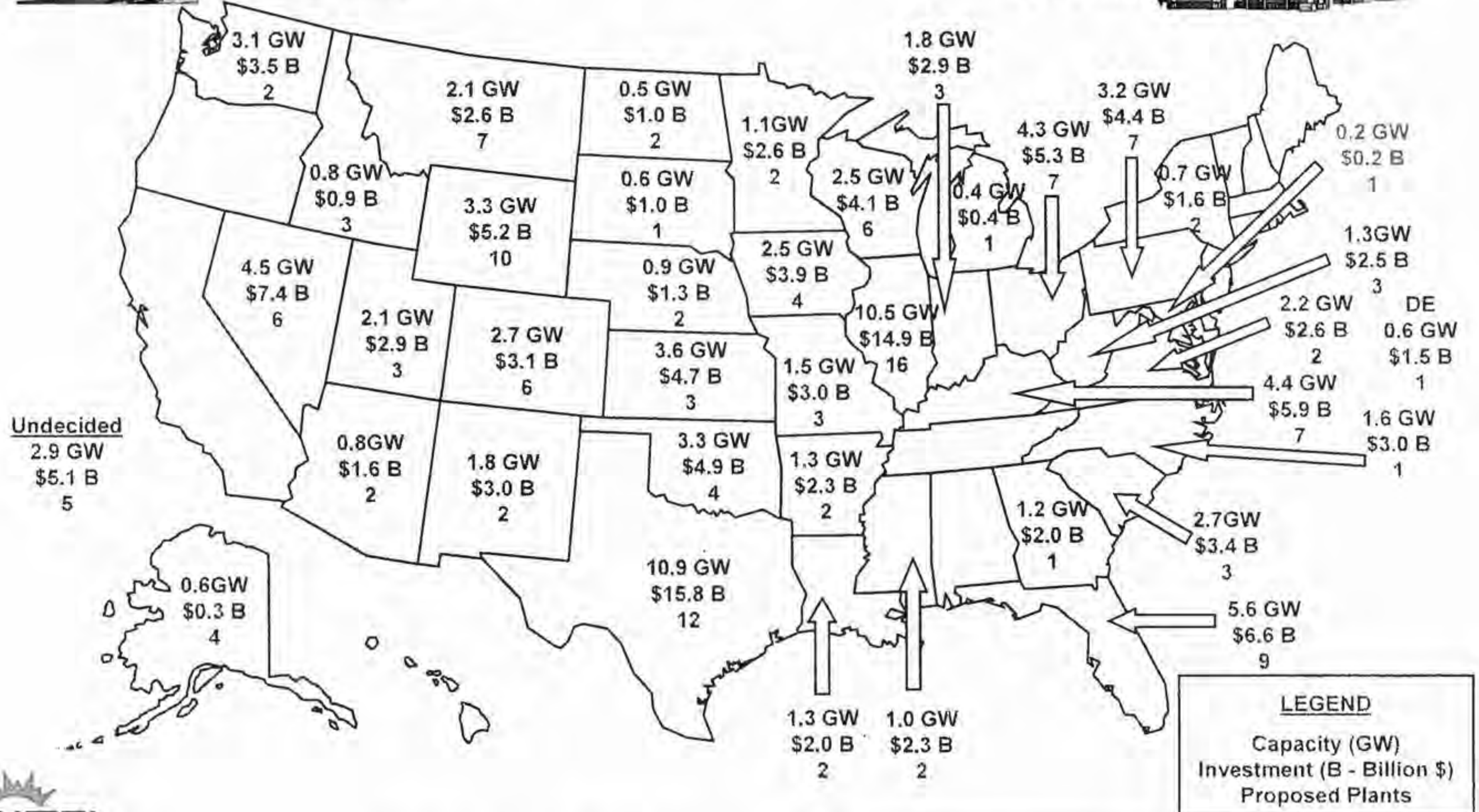
Coal's Resurgence in Electric Power Generation

Proposed New Plants

Equivalent Power for 96 Million Homes

159 Plants
96GW
$ 141 Billion



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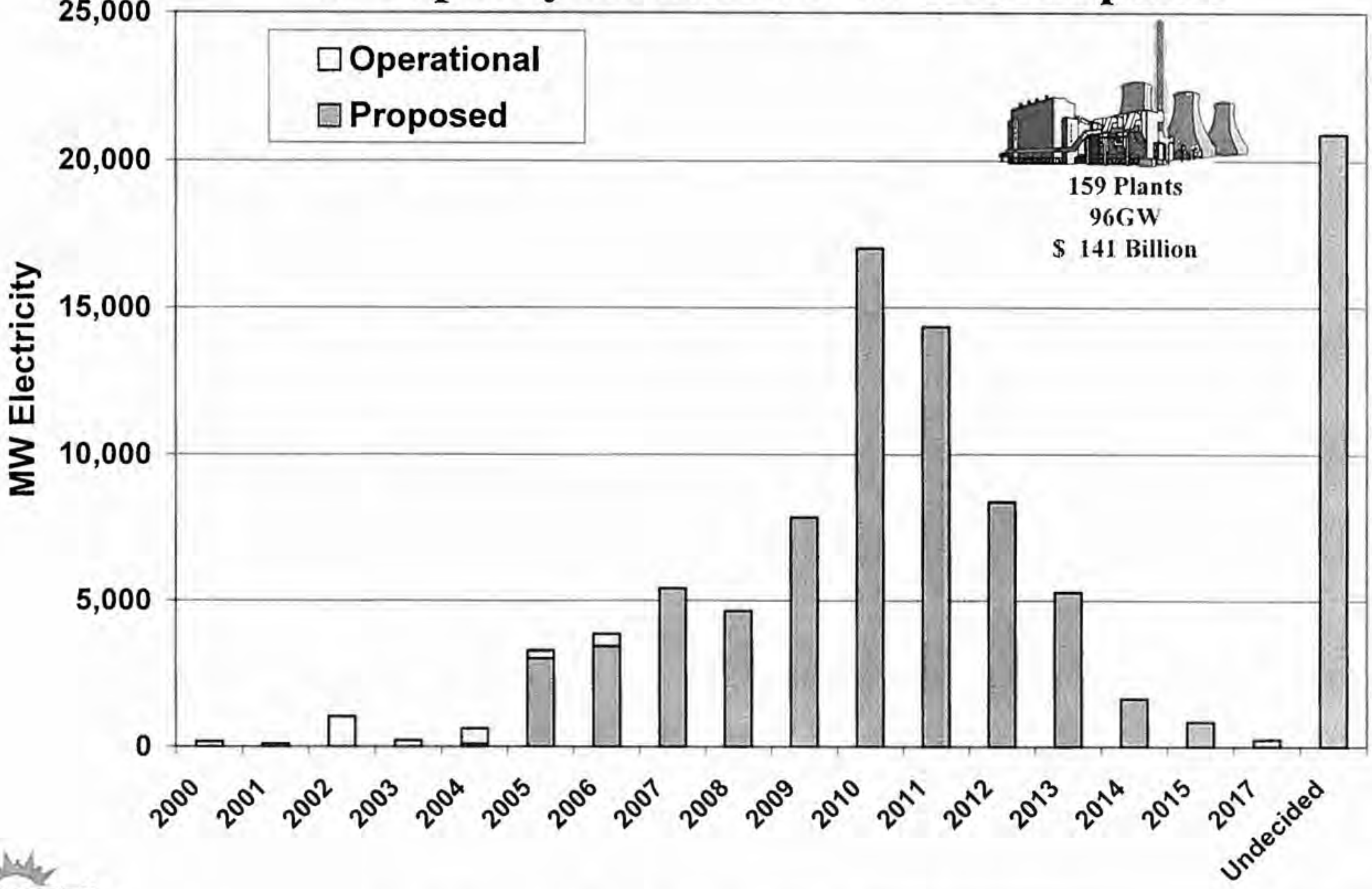
OCES 1/24/2007

Coal's Resurgence in Electric Power Generation
** Annual Capacity Additions New and Proposed**



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Coal's Resurgence State Summary

159 Plants
96GW
$ 141 Billion

Equivalent Power
for
96 Million Homes

State	Plants	Capacity (MW)	% Capacity	Investment (Million $)	% Investment
Alabama	0	0	0.0	$0	0.0
Alaska	4	600	0.6	$250	0.2
Arizona	2	818	0.9	$1,589	1.1
Arkansas	2	1,265	1.3	$2,300	1.6
California	0	0	0.0	$0	0.0
Colorado	6	2,714	2.8	$3,142	2.2
Delaware	1	630	0.7	$1,500	1.1
Florida	9	5,567	5.8	$6,580	4.7
Georgia	1	1,200	1.3	$2,000	1.4
Idaho	3	750	0.8	$850	0.6
Illinois	16	10,509	11.0	$14,935	10.6
Indiana	3	1,760	1.8	$2,900	2.0
Iowa	4	2,540	2.6	$3,900	2.8
Kansas	3	3,550	3.7	$4,650	3.3
Kentucky	7	4,406	4.6	$5,887	4.2
Louisiana	2	1,275	1.3	$2,000	1.4
Maryland	1	180	0.2	$180	0.1
Michigan	1	425	0.4	$425	0.3
Minnesota	2	1,153	1.2	$2,600	1.8
Mississippi	2	1,040	1.1	$2,300	1.6
Missouri	3	1,150	1.2	$2,997	2.1
Montana	7	2,078	2.2	$2,635	1.9
Nebraska	2	880	0.9	$1,295	0.9
Nevada	6	4,515	4.7	$7,365	5.2
New Mexico	2	1,800	1.9	$3,000	2.1
New York	2	720	0.8	$1,645	1.2
North Carolina	1	1,600	1.7	$3,000	2.1
North Dakota	2	540	0.6	$957	0.7
Ohio	7	4,310	4.5	$5,255	3.7
Oklahoma	4	3,300	3.4	$4,900	3.5
Oregon	0	0	0.0	$0	0.0
Pennsylvania	7	3,151	3.3	$4,437	3.1
South Carolina	3	2,680	2.8	$3,384	2.4
South Dakota	1	600	0.6	$1,000	0.7
Tennessee	0	0	0.0	$0	0.0
Texas	12	10,870	11.3	$15,800	11.2
Utah	3	2,070	2.2	$2,850	2.0
Virginia	2	2,200	2.3	$2,600	1.8
Washington	2	3,100	3.2	$3,500	2.5
West Virginia	3	1,345	1.4	$2,455	1.7
Wisconsin	6	2,500	2.6	$4,100	2.9
Wyoming	10	3,279	3.4	$5,214	3.7
Undecided	5	2,900	3.0	$5,100	3.6
TOTALS	159	95,970	100	$141,477	100

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Coal's Resurgence in Electric Power Generation

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~~TVA Bellefonte Site~~	~~Alabama~~ ~~Jackson County~~	~~1500 MW~~ ~~IGCC Texaco~~	Cancelled (4/2003) ~~In Service - 2005~~	~~~ $1.5 Billion~~	~~High Sulfur Coal~~ ~~Illinois Basin~~	8, 7, 9, 12
Matanuska Electric Association	Alaska	100 MW	Proposed (11/2006) In Service - 2015	~ $100 Million	Coal	1
Nuvista	Alaska Bethel	100 MW	Proposed (3/2004) In Service - 2010	~ $100 Million	Coal	11
Homer Electric Association	Alaska Healy	50 MW	Proposed (11/2006) In Service - 2014	~ $50 Million	Coal	1
~~Usibelli Coal Mine Inc.~~	~~Alaska~~ ~~Healy~~	~~200 MW~~	Cancelled (1/2007) ~~In Service - TBD~~	~~$421 Million~~	~~Coal~~	1, 6
Agrium US	Alaska Kenai	350 MW Gasification	Feasibility study (12/2005) In Service - 2011	TBD	Coal	11
~~Reliant Resources~~ ~~Hopi Tribe~~	~~Arizona~~ ~~Not yet located~~	~~1,200 MW~~	Cancelled (5/2002) ~~In Service - 2008~~	~~~ $1.2 Billion~~	~~low Sulfur Sub-bituminous~~	11, 24
Tucson Electric Power	Arizona Springerville	418MW	Operational (7/2006) In Service - 2006	$939 Million	Sub-Bituminous	2, 3, 4, 7, 12
Tucson Electric Power	Arizona Springerville	400 MW	Near Construction (7/2006) In Service - 2009	$650 Million	PRB & local Western Coal	7
~~Alabama Electric~~	~~Arizona~~ ~~Sumter County~~	~~500 MW~~	Cancelled ~~In Service - 2007~~	~~~ $500 Million~~	~~Sub Bituminous~~	9, 6
~~Fort Chaffee Authority~~	~~Arkansas~~ ~~Fort Chaffee~~	~~2 Plants~~ ~~750 MW each~~	Cancelled ~~In Service - 2007~~	~~$2.5 Billion~~	~~Arkansas Coal~~	11
Southwestern Electric Power Company	Arkansas Hempstead County	600 MW Ultra-Supercritical	Proposed (8/2006) In Service - 2011	$1.3 Billion	PRB Coal Wyoming	1

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LS Power Development	Arkansas Osceola	665 MW	Construction (12/2006) In Service - 2010	$1 Billion	Powder River Basin Coal	6, 9, 11, 1
~~Fernald Power~~	~~California Humbolt City~~	~~2,500 MW~~	Indefinitely On Hold ~~In Service - TBD~~	~~~$2.5 Billion~~	~~Coal~~	~~11~~
Radar Acquisitions Corp. / Kiewit	Colorado	400 - 500 MW	Feasibility Study (10/2003) In Service - TBD	~$500 Million	Coal	11
DOE Foster Wheeler	Colorado Colorado Springs	150 MW CFB	On Hold (12/2003) In Service - 2008	$275 Million	Coal	1, 11
Tri-State Generation and Transmission	Colorado Front Range	1,000 MW	Proposed (10/2004) In Service - 2011	~$1 Billion	Coal	1
Larmar Light & Power Ark. River Power Auth.	Colorado Lamar	39 MW increase Conversion	Near Construction (4/2006) In Service - TBD	$67 Million	Coal to replace natural gas	2
~~Tri-State Generation and Transmission~~	~~Colorado Las Animas~~	~~3 Units 400 MW each~~	Cancelled (4/03) ~~In Service - 2005,06,07~~	~~$1.2 Billion~~	~~Coal~~	11, 4, 12
Xcel Energy	Colorado Pueblo	750MW Super-critical	Construction (11/2006) In Service - 2009	$1.3 Billion	PRB Coal	1, 11
Xcel Energy	Colorado	300-350MW IGCC	Proposed (8/2006) In Service - TBD	TBD	Coal	1, 11
~~Deseret Generation & Transmission Corp.~~	~~Colorado Rangely~~	~~80 MW~~	Cancelled (1/2005) ~~In Service - 2004~~	~~$ 140 Million~~	~~Waste Coal~~	1, 3, 12
NRG	Delaware Indian River	630 MW IGCC	Feasibility Study (1/2007) In Service -	$1.5 Billion	Coal	11
~~Florida Municipal Power Agency~~	~~Florida~~	~~500-600 MW~~	No Plans (8/2006) ~~In Service - 2009~~	~~$600 Million~~	~~Coal~~	11, 6

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Florida Power & Light	Florida Crystal River	100 MW	Operational In Service - 2001	~ $100 Million	Coal	12
Jacksonville Electric	Florida Duval	(2) 300 MW Units CFB	Operational (7/2002) In Service - 2002	~$600 Million	Coal/Pet Coke	12, 3, 9
Florida Power & Light	Florida Glades County	(2) 980 MW Units Ultra-Supercritical	Permitting (1/2007) In Service - 2012, 13	~$1 Billion	Appalachian Coal	7, 11
Orlando Utilities Comm. Southern Co, & U.S. DOE	Florida Orange County	285 MW IGCC	Proposed (1/2007) In Service - 2010	$750 Million	Coal	1, 2
~~Lakeland Electric & Water~~	~~Florida Polk County~~	~~350 MW~~	Cancelled ~~In Service - TBD~~	~~~$350 Million~~	~~Coal~~	12
Tampa Electric	Florida Polk County	630 MW IGCC	Proposal (11/2006) In Service - 2013	~$630 Million	Coal	1
Seminole Electric Cooperative	Florida Putnam County	750 MW	Permitting (1/2007) In Service - 2012	$1.2 Billion	Coal	1, 11
~~Florida Power & Light~~	~~Florida St. Lucie County~~	~~(2) 425 MW Units Super critical~~	Rejected (11/2005) ~~In Service - 2012, 13~~	~~~$1 Billion~~	~~Coal~~	1, 11, 23
Florida Power & Light	Florida St. Lucie County	TBD IGCC	Feasibility Study (6/2006) In Service - TBD	TBD	Coal	11
JEA	Florida Taylor County	800 MW	Developing (6/2006) In Service - 2012	$1.5 Billion	Mix of Coals	1, 2, 11
Southern Company	Florida Taylor County	787 MW Supercritical	Proposed (6/2006) In Service - 2012	~$800 Million	Coal	11
Longleaf Energy (LS Power Development)	Georgia Early County	1,200 MW 2 (600MW Units)	Permitting (11/2006) In Service - 2005	$2.0 Billion	Coal	6, 25

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~~Sempra Energy Resources~~	~~Idaho~~ ~~Elmore or Jerome~~	~~600 MW~~ ~~Super Critical~~	Cancelled (3/2006) ~~In Service - 2011~~	~~$1 Billion~~	~~Coal~~ ~~PRB~~	21, 11
Southeast Idaho Energy LLC	Idaho Pocatello	~ 500 MW IGCC	Proposed (3/2005) In Service - 2010	$850 Million	Coal	2
Idaho Power Company	Idaho Pocatello /Soda Springs	TBD IGCC	Proposed (11/2006) In Service - 2017	TBD	Coal	1, 11
Mountain Island Energy Holdings, LLC	Idaho Soda Springs	250 MW IGCC	Proposed (1/2007) In Service - 2013	TBD	Coal	1
Dynegy	Illinois Baldwin	2 Plants 650 MW each	Proposed (10/2001) In Service - 2007	$1.5 Billion	Illinois Coal	1
Illinois Energy Group	Illinois Benton	2 units 750 MW each	Proposed (8/2002) In Service - TBD	$1.7 Billion	Coal	11, 17
Secure Energy LLC	Illinois Decatur	Coal-to-Synthetic Gas	Proposed (5/2006) In Service - 2008	TBD	Coal	1, 11
Rentech Development Corp.	Illinois East Dubuque	76 MW & Fuels Gasification	Proposed (6/2006) In Service - 2009	$810 Million	Coal	7, 11
Corn Belt Energy	Illinois Elkhart	91 MW LEBS	Development (6/2005) In Service - TBD	$140 Million	Waste Coal	1, 2, 8, 12
Turris Coal Company	Illinois Elkhart	25 - 35 MW	Proposed (10/2001) In Service - TBD	~ $35 Million	Coal	11
Indeck Energy Service	Illinois Elwood	600 MW CFB	On Hold (11/2005) In Service - 2007	$1 Billion	Illinois Coal	1, 12, 8
Clean Coal Power Resources	Illinois Fayette County	2,400 MW & Fuels Gasification	Proposal (10/2002) In Service - TBD	$2.8 Billion	Coal	11

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EnviroPower	Illinois Franklin County	600 MW	Re-Permitting (10/2006) In Service - 2007	~ $600 Million	Coal	8, 12
Madison Power Corp.	Illinois Marion	500 MW Gasification	Proposal (6/2005) In Service - TBD	$2.0 Billion	Coal (Mine-Mouth)	2
Southern Illinois Power	Illinois Marion	120 MW	Operational (6/2003) In Service - 2003	$50 Million	Bituminous Coal Fines	8, 9, 12
City Water, Light & Power	Illinois Springfield	200 MW	Development (9/2005) In Service - 2010	~$200 Million	Coal	12, 1
Erora Group	Illinois Taylorville	777 MW IGCC / Coprod.	Development (7/2006) In Service - 2010	1.1 Billion	Illinois Coal (Mine-Mouth)	1, 19, 11
Peabody Energy / Prairie State Energy Campus	Illinois Washington City	2 units 750 MW each	Near Construction (10/2006) In Service - 2011	$2.0 Billion	Illinois Coal High Sulfur	1, 11, 12
United Supply of America	Illinois White County	270 MW CFB	Proposal (10/2005) In Service - TBD	$400 Million	Coal (Mine Mouth) & Waste Coal	1
Steelhead Energy Company LLC	Illinois Williamson County	545 MW IGCC	Proposal (6/2005) In Service - TBD	$600 Million	Coal	1
Duke Energy (Cinergy)	Indiana Edwardsport	630 MW IGCC	Permitting (11/2006) In Service - TBD	$1.3 Billion	Coal	23, 11
~~EnviroPower~~	~~Indiana Fayette County~~	~~525 MW~~	~~Development (7/2002) In Service 2004~~	~~~$525 Million~~	~~Waste Coal~~	12, 8
~~EnviroPower~~	~~Indiana Pike County~~	~~500 MW~~	~~Initiate 2001~~ Cancelled 2002	~~$600 Million~~	~~Waste Coal~~	2, 5, 8, 9, 12
Tondu Corp.	Indiana St. Joseph County	630 MW IGCC	Considering (9/2005) In Service - TBD	$1 Billion	Coal	2

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EnviroPower	Indiana Sullivan County	500 MW	Permitting (10/2002) In Service - TBD	$600 Million	Waste Coal	2, 5, 8, 9, 12
~~Alliant Energy~~	~~Iowa~~	~~450 MW~~	~~Development (5/2003)~~ Cancelled - 2003	~~~$450 Million~~	~~Coal~~	12, 1
MidAmerican Energy	Iowa Council Bluffs	790 MW Super-critical	Construction (8/2004) In Service - 2007	$1.2 Billion	Coal	13, 1, 8, 11
Interstate Power and Light	Iowa Marshalltown	600 MW	Proposal (1/2007) In Service - 2013	$1.0 Billion	Coal	11
Dairyland Power Cooperative	Iowa Mitchell or Chickasaw	400 MW	On Hold (12/2004) In Service - 2009-2014	~$400 Million	Low Sulfur PRB and Colorado	2, 11
LS Power	Iowa Waterloo	750 MW	Proposal (1/2007) In Service - 2011	$1.3 Billion	Coal	1
Sunflower Electric Power Corp.	Kansas Garden City (Holcomb)	3 - 700 MW Units Supercritical	Near Construct. (12/2006) In Service - 2011, 12, 13	2.5 Billion	Coal PRB	1, 11, 12, 7
Great Plains Energy	Kansas	850 MW	On Hold (7/2004) In Service - TBD	~ $850 Million	Coal	1,
Westar Energy Inc.	Kansas	600 MW	Postponed (12/2006) In Service - 2013	$1.3 Billion	Coal	2
EnviroPower	Kentucky Calvert City	500 MW	Development (8/2002) In Service - TBD	$600 Million	Coal & Waste Coal	1, 2
Peabody Energy/ Thoroughbred Campus	Kentucky Muhlenberg	2 Units 750 MW each	Permitting (5/2006) In Service - 2007	$2.1 Billion	Western Kentucky High Sulfur Coal	1, 3, 9, 12, 16
Estill County Energy Partners	Kentucky Estill County	110 MW CFB	Development (10/2004) In Service - 2008	$150 Million	Waste Coal	11, 2, 18

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Cash Creek Generation	Kentucky Henderson City	1,000 MW	Permitting (11/2001) In Service - 2006	$1 Billion	Coal	1
~~Kentucky Mountain Power (EnviroPower)~~	~~Kentucky Knott County~~	~~525 MW~~	Suspended (4/2004) In Service - 2006	~~$600 Million~~	~~Waste Coal & New Coal~~	1, 2, 9, 12, 18
East Kentucky Power co-op	Kentucky Maysville	268 MW CFB	Operational (3/2005) In Service - 2005	$367 Million	Coal	15, 8, 12
East Kentucky Power co-op	Kentucky Clark County	278 MW CFB	Approved (8/2006) In Service - 2010	$470 Million	Coal	2, 22, 7
~~Global - Kentucky Pioneer Energy - DOE~~	~~Kentucky Clark County~~	~~540 MW IGCC~~	Cancelled (10/2006) ~~In Service - 2004~~	~~~$540 Million~~	~~20% Coal 80% Waste~~	12, 1, 11, 18
LG&E Powergen	Kentucky Trimble County	750 MW Super-critical	Approved (7/2006) In Service - 2010	$1.2 Billion	Coal Illinois Basin	11, 1, 2, 19
Cleco Power	Louisiana Boyce	600 MW 2-CFB units	Development (4/2006) In Service - 2009	$1 Billion	Coal Pet Coke	1, 11, 19
NRG Energy	Louisiana New Roads	675 MW Super-critical	Permitting (8/2005) In Service - 2009	$1 Billion	Coal	11, 8
AES Corporation	Maryland Cumberland	180 MW CFB	Operational In Service - 2000	~ $180 Million	Maryland Coal	2, 7
Manistee Saltwork Tondu Corp.	Michigan Manistee	425 MW	On Hold (11/2004) In Service - 2006	~ $ 425 Million	Coal	2, 12
~~Great River Energy~~	~~Minnesota Dakota County~~	~~250-500 MW IGCC or CFBC~~	Cancelled (10/2006) ~~In Service - 2008~~	~~~$500 Million~~	~~Coal~~	11
~~Minnesota Power~~	~~Minnesota Grand Rapids~~	~~225 MW~~	Cancelled (8/2002) ~~In Service 2005~~	~~~$200 Million~~	~~Coal~~	6, 11

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Excelsior Energy Mesaba Energy Project	Minnesota Itasca County	603 MW Gasification	Permitting (1/2007) In Service - 2011	$2.0 Billion	Coal	11, 19
Xcel Energy / LS Power	Minnesota Rosemount	550 MW	Preliminary (3/2003) In Service - TBD	~$ 600 Million	Coal	1, 2
Tractebel Power	Mississippi Choctaw County	440 MW	Operational In Service - 2002	$500 Million	Lignite	2, 11,12, 7
Mississippi Power Co. Southern Company	Mississippi Kemper County	600 MW Gasification	Proposal (12/2005) In Service - 2013	$1.8 Billion	Lignite	1, 11
Associated Electric Cooperative Inc.	Missouri Carroll County	TBD	Proposed (4/2005) In Service - TBD	$1 Billion	Coal	2
Springfield City Council	Missouri Springfield	300 MW Additional	Voters Approved (6/2006) In Service - TBD	$ 697 Million	PRB Coal	11
~~Great Plains Power~~	~~Missouri~~ ~~Weston~~	~~750 MW~~	Not being Considered (5/2004) ~~In Service - 2005~~	~~~$750 Million~~	~~Coal~~	12, 1, 8
Great Plains Energy Kansas City Power & Light	Missouri Weston	850 MW Supercritical	Near Construct. (8/2006) In Service - 2011	$1.3 Billion	PRB Coal	1, 12
~~Composite Power~~	~~Montana~~ ~~Bear Creek~~	~~4 Plants~~ ~~500 MW each~~	Cancelled (2/2003) ~~In Service - 2004,6,8~~	~~$1.5 Billion~~	~~Montana~~ ~~Coal~~	2, 8, 12
~~Bull Mountain~~ ~~Development~~	~~Montana~~ ~~Billings~~	~~2 Units~~ ~~350 MW each~~	Air Permit Expired (7/2005) Project Changed to CTL	~~~$700 Million~~	~~Coal~~	8, 12, 11
Bull Mountain Development	Montana Billings	300 MW Coal to Liquids	Proposed (7/2006) In Service - TBD	TBD	Montana (Mine-Mouth) Coal	11
Southern Montana Electric Gen & Trans	Montana Great Falls	250 MW CFB	Proposed (7/2006) In Service - 2011	$515 Million	Powder River Basin Coal	21, 11

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Centennial Power	Montana Hardin	116 MW	Construction (8/2004) In Service - 2005	~ $150 Million	Coal	11, 1, 8, 12
Great Northern Power Development / Kiewit	Montana Miles City	500 MW CFB	Proposal (8/2004) In Service - 2008	$900 Million	Lignite (Wind also)	1, 2, 11, 12
Thompson River Co-Gen LLC	Montana Thompson River	12.5 MW	Operational (11/2005) In Service - 2005	~ $20 Million	Coal & Wood Waste	18
Comanche Park LLC	Montana Yellowstone City	2 Units 100 MW each	Development (7/2002) In Service - 2004-05	$300 Million	Montana Coal	1
Bechtel / Kennecott Energy	Montana Undetermined	750 MW Phase I	Proposal (10/2003) In Service - 2010	~ $750 Million	Montana (Mine-Mouth) Coal	11
Hastings Utilities, Grand Island	Nebraska Hastings	220 MW	Board Approved (12/2004) In Service - 2012	$445 Million	Coal	2
Omaha Public Power District	Nebraska Nebraska City	660 MW	Construction (1/2007) In Service - 2009	$850 Million	Powder River Basin Coal	1, 11, 19
Sempra Granite Fox Power	Nevada Gerlach	2 - 725 MW Units Super-critical	Study on Hold (3/2006) In Service - 2010, 11	$2.0 Billion	Powder River Basin Coal	2, 11
Newmont Mining Corp.	Nevada Elko	200 MW	Near Construction (3/2006) In Service - 2008	$450 Million	Coal	1, 12, 25
Barrick Gold	Nevada East of Reno	115 MW	Considering (7/2004) In Service - TBD	~ $115 Million	Coal	1
Sithe Global Power	Nevada Mesquite	750 MW	Proposal (2/2006) In Service - 2011	$1 Billion	Coal	1
LS Power Associates White Pine Energy	Nevada White Pine County	500 MW (out of a possible 1600MW)	Developing (8/2006) In Service - 2010	~ $ 0.6 - 1 Billion	Powder River Basin Coal	1, 2

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Sierra Pacific	Nevada White Pine County	2 - 750 MW Units	Proposal (8/2006) In Service - 2011, 2014	$3.0 Billion (w/ Transm. Line)	Coal	11
Sithe Global Power Dine Power Authority	New Mexico Farmington	1,500 MW Supercritical	Air Permit Approved (12/2006) In Service - 2010	$2.5 Billion	Low Sulfur Sub Bit Coal, Mine Mouth	1, 2, 12
Peabody Energy / Mustang Energy	New Mexico Milan	300 MW	Permitting Stage (11/2005) In Service - 2006	$500 Million	Coal	11, 12, 8
Jamestown Board of Public Utilities	New York Jamestown	40 MW CFB	Proposal (11/2006) In Service - 2011	$145 Million	Coal, Petroleum coke, Wood	12
NRG (Awarded CCPPI)	New York Tonawanda	680 MW Gasification	Proposal (1/2007) In Service - 2013	$1.5 Billion	Eastern Coal Pet Coke	1, 11
Duke Energy	North Carolina Cliffside	1600 MW 2 (800MW) Units	Proposal (1/2007) In Service - 2011, TBD	$3.0 Billion	Coal	7, 1
~~Montana-Dakota Utility Westmoreland Power~~	~~North Dakota Gascoyne~~	~~175 MW~~	Canceled (5/2006) In Service - 2010	~~$300 Million~~	~~North Dakota Lignite~~	2, 3, 4, 8, 12
Great River Energy	North Dakota Jamestown	40 MW Power & Heat	Development (5/2006) In Service - TBD	$157 Million	North Dakota Lignite	11
~~Great River Energy~~	~~North Dakota TBD~~	~~500 MW~~	Canceled (1/2003) ~~In Service - 2010~~	~~$700 Million~~	~~North Dakota Lignite~~	11, 12, 1
South Heart Coal	North Dakota Stark County	500 MW CFB	Proposed (8/2005) In Service - 2008	$800 million	North Dakota Lignite	11
Nordic Energy	Ohio Ashtabula	830 MW Cogeneration	Permitting (5/2004) In Service - 2006	$1.2 Billion	Coal	8, 11
Dominion Energy	Ohio Conneaut	600 MW	Considering (7/2004) In Service - 2010	~ $600 Million	Coal	11

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CME International	Ohio Hanging Rock	600 MW IGCC	Considering (11/2005) In Service - TBD	~ $600 Million	Coal	1
American Municipal Power-Ohio	Ohio Letart	1,000 MW	Permitting (6/2006) In Service - 2012	$1.2 Billion	Blend of Ohio & PRB Coals	11
Global Energy	Ohio Lima	600 MW IGCC	Near Construction (12/2005) In Service - 2008	$575 Million	Coal Fines Pet Coke	1, 7, 3, 9, 11, 12
American Electric Power	Ohio Meigs County	600MW IGCC	Proposed (1/2007) In Service - 2010	$1.0 Billion	Coal	1, 11
Sunoco	Ohio Scioto County	80 MW Cogeneration	Proposed (9/2004) In Service - 2006	~ $80 Million	Coal	12
SynFuel	Oklahoma Enid	600 MW & Fuels Gasification	Initiate - 2001 In Service - 2008	$900 Million	Coal	8
Western Farmers Electric Cooperative	Oklahoma Hugo	750 MW	Proposed (3/2006) In Service - 2011	$1.2 Billion	Coal	1
Oklahoma Gas and Electric	Oklahoma Red Rock	950 MW Ultra-Supercritical	Near Construction (1/2007) In Service - 2011	$1.8 Billion	PRB Coal	
LS Power Development	Oklahoma Sequoyah	1,000 MW	On Hold (8/2002) In Service - TBD	~ $1 Billion	Coal	6, 8
~~PacifiCorp~~	~~Oregon~~	~~500 MW~~	Cancelled (10/2006) ~~In Service - 2004~~	~~~ $500 Million~~	~~Coal~~	8, 1
~~AES Corporation~~	~~Pennsylvania~~ ~~Beaver~~	~~800 MW~~	Cancelled ~~In Service - TBD~~	~~~ $ 800 Million~~	~~Coal~~	8
River Hill Power LLC	Pennsylvania Clearfield County	290 MW CFB (Cogen.)	Proposal (8/2005) In Service - 2008	~ $300 Million	Waste Coal	25

Red text above indicates recent updates

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Coal's Resurgence in Electric Power Generation

** Database **

SPONSOR	PROPOSED LOCATION	SIZE TECHNOLOGY	TIMING Status - (Date indicates latest reference) In Service - Planned Date	INVESTMENT	COAL TYPE	SOURCES
Wellington Development	Pennsylvania Greene County	525 MW CFB	Air Permit (12/2006) In Service - 2008	$800 Million	Waste Coal	11
Reliant Energy	Pennsylvania Indiana	520 MW CFB	Operational (9/2004) In Service - 2004	$800 Million	Waste Coal	1, 2, 8, 12
Waste Management and Processors Inc	Pennsylvania Schuylkill County	41 MW & Fuels Liquefaction	Development (1/2006) In Service - 2009	$612 Million	Anthracite Coal Waste & Petcoke	11
EnviroPower	Pennsylvania Somerset	525 MW	Initiate - 2002 In Service - TBD	~ $525 Million	Coal	8
PA Energy Development Corp.	Pennsylvania Southwestern region	1,000 MW	Proposed (4/2004) In Service - TBD	~ $1 Billion	Coal	2
Robinson Power CO.	Pennsylvania Washington County	250 MW CFB	Proposed (4/2005) In Service - TBD	$400 Million	Waste Coal	2, 25
Santee Cooper	South Carolina Berkeley County	2 Units 640 MW each	Construction (10/2006) In Service - 2007, 2009	$1.4 Billion	Coal Petcoke	1, 12, 2
Santee Cooper	South Carolina S. Florence County	600 MW Ultra-Supercritical	Proposed (10/2006) In Service - 2012	$984 Million	Coal	11, 1
LS Power Development	South Carolina Marion City	500-1,100 MW	Permitting (8/2002) In Service - 2006	~ $ 1 Billion	Coal	6, 11
Otter Tail Power Company	South Dakota Milbank	600 MW Super-Critical	Permitting (6/2006) In Service - 2011	$ 1 Billion	Coal	2, 11, 25
~~CME North America Merchant Energy~~	~~Tennessee Chattanooga~~	~~1000 MW~~	Cancelled (9/2006) ~~In Service - 2007~~	~~~ $ 1 Billion~~	~~Coal~~	3, 11, 12, 6
~~Pickwick Power TVA~~	~~Tennessee Hardin County~~	~~100 MW CFB~~	Cancelled (1/2003) ~~In Service - 2004~~	~~$100 Million~~	~~Coal~~	13, 11, 8, 12

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Coal's Resurgence in Electric Power Generation

** Database **

SPONSOR	PROPOSED LOCATION	SIZE TECHNOLOGY	TIMING Status - (Date indicates latest reference) In Service - Planned Date	INVESTMENT	COAL TYPE	SOURCES
TXU	Texas Existing Plants	6,400 MW 8Units @ 7Plants	Permitting (1/2007) In Service - 2010	$10 Billion	Coal PRB	1, 11
Sempra Generation	Texas Bremond	600 MW	Proposal (7/2005) In Service - 2011	$800 Million	Lignite Coal	1
City Public Service Board of San Antonio	Texas Calaveras Lake	750 MW	Construction (3/2006) In Service - 2010	$1 Billion	Coal PRB	1, 11
TXU	Texas Milam County	600 MW CFB	Near Construction (1/2007) In Service - 2009	$1 Billion	Lignite Coal	11, 7
LS Power Development	Texas Riesel	800 MW	Permitting (5/2006) In Service - 2011	$1 Billion	Coal PRB	12
TXU	Texas Robertson County	1720 MW Supercritical	Permitting (1/2007) In Service - 2009	~$2.0 Billion	Coal Texas Lignite	11, 19
~~San Antonio Public Service Bd.~~	~~Texas~~ ~~San Antonio~~	~~500 MW~~	Cancelled ~~In Service - 2004~~	~~~$500 Million~~	Coal	14
PacifiCorp	Utah Emery	850 MW	Development (10/2006) In Service - 2014	$800 Million	Coal	12, 2
Intermountain Power	Utah Delta	950 MW	Development (11/2006) In Service - 2012	$1.7 Billion	Coal	3, 4, 8, 12, 10, 20
Nevco Energy	Utah Sigurd	270 MW CFB	Proposed (6/2004) In Service - 2008	$350 Million	Coal	11
~~Duke Energy North America~~	~~Virginia~~ ~~Isle of Wright~~	~~700 MW~~ Gasification	Cancelled (9/2002) ~~In Service 2008~~	~~$800 Million~~	Coal	1
LS Power Development	Virginia Sussex County	1,600 MW	Permitting (8/2002) In Service - 2005	~ $1.6 Billion	Coal	6, 8, 1

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Coal's Resurgence in Electric Power Generation

** Database **

SPONSOR	PROPOSED LOCATION	SIZE TECHNOLOGY	TIMING Status - (Date indicates latest reference) In Service - Planned Date	INVESTMENT	COAL TYPE	SOURCES
Dominion, AEP, Appalachian Power	Virginia Wise County	600 MW CFB	Proposed (9/2006) In Service - 2011	$1 Billion	Virginia Coal or Waste coal/Biomass	2, 11
Composite Power	Washington Richland	2500 MW Refurbish old site	Assessment (8/2001) In Service - TBD	~ $2.5 Billion	Coal	11
Energy Northwest	Washington Kalama	600 MW IGCC	Proposal (6/2006) In Service - 2012	$1 Billion	Coal, PRB, Petcoke	11, 1
~~U.S. Electric Power Globaltex~~	~~Washington Whatcom County~~	~~249 MW~~	Cancelled (4/2003) ~~In Service - 2004~~	~~~ $ 250 Million~~	~~Low Sulfur Coal Vancouver~~	1, 3, 4, 8, 12
GenPower LLC Longview	West Virginia Monogalia County	660 MW Supercritical	Near Construction (10/2006) In Service - 2010	$940 Million	Coal	2, 11
Western Greenbrier CO-Generation / DOE	West Virginia Greenbrier County	85 MW Advanced CFB	DOE Approved - (1/2007) In Service - 2010	$215 Million	Waste Coal	1, 11
Appalachian Power (American Electric Power)	West Virginia Mason County	600MW IGCC	Air Permit filed (1/2007) In Service - 2012	$1.3Billion	Coal	1, 11
~~North American Power Group Ltd.~~	~~West Virginia Not yet located~~	~~300 MW~~	Cancelled ~~In Service - 2005~~	~~~$300 Million~~	~~Coal~~	14
~~Anker Energy~~	~~West Virginia Upshur County~~	~~450 MW~~	Cancelled ~~In Service - 2006~~	~~$600 Million~~	~~Central App. Coal & Waste Coal~~	1, 2, 11, 12
Alliant Energy Wis. Power & Light	Wisconsin Portage	300 MW	Considering (4/2006) In Service - 2013	~ $300 Million	Coal PRB	1, 9, 12, 11
Wisconsin Power and Light	Wisconsin Cassville	300 MW CFB	Considering (4/2006) In Service - 2013	~ $300 Million	Coal	11
MidAmerican Energy	Wisconsin Cassville	200 MW	Proposal - (9/2002) In Service - TBD	~ $250 Million	Coal	8, 12

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Coal's Resurgence in Electric Power Generation

** Database **

SPONSOR	PROPOSED LOCATION	SIZE TECHNOLOGY	TIMING Status - (Date indicates latest reference) In Service - Planned Date	INVESTMENT	COAL TYPE	SOURCES
Wisconsin Energy & Madison Gas	Wisconsin Oak Creek	2 Plants (s-critical) 600 MW each	Construction (11/2005) In Service - 2009-10	$2.5 Billion	Powder River Basin Sub-Bituminous	11, 1, 12, 2, 7
Wisconsin Public Service Corp.	Wisconsin Wausau	500 MW	Construction (6/2005) In Service - 2008	$750 Million	Low-Sulfur Coal	1, 2, 11
North American Power Group	Wyoming Campbell County	320 MW	Construction (6/2005) In Service - 2008	$ 655 Million	Waste Coal	4, 6, 7, 12
North American Power Group	Wyoming Campbell County	750 MW Super-critical	Proposal (9/2006) In Service - TBD	TBD	Coal	Casper Star Tribune
~~North American Power Group~~	~~Wyoming~~ ~~Campbell County~~	~~500 MW~~	Cancelled (2/2003) In Service - 2005	~~$ 750 Million~~	~~Powder River Basin~~ ~~Waste Coal~~	6, 12
Basin Electric Power Cooperative	Wyoming Gillette	375 MW	Applied Air Permit(7/2006) In Service - 2011	$800 Million	Powder River Basin Coal	2, 7, 11
Black Hills Corp.	Wyoming Gillette	90 MW	Operational (3/2003) In Service - 2003	$100 Million	Powder River Basin Sub-Bituminous	2, 4, 7, 12
Black Hills Corp.	Wyoming Gillette	90 MW	Construction (1/2006) In Service - 2008	$169 Million	Powder River Basin Sub-Bituminous	2, 3, 4, 7, 12
Rentech	Wyoming Gillette	104 MW & Fuels Gasification	Proposed (10/2005) In Service - 2010	$740 Million	Coal	11
Buffalo Energy	Wyoming Glenrock	1100 MW IGCC - 3 Units	Proposed (12/2006) In Service - 2009	TBD	Coal	11
DKRW & SNC-Lavalin	Wyoming Medicine Bow	200 MW & Fuels Gasification	Development (8/2006) In Service - 2010	$2.5 Billion	Wyoming Coal	1, 11
Idaho Power Company	Wyoming Rock Springs	250 MW	Proposed (11/2006) In Service - 2013	~ $250 Million	Coal	11

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Coal's Resurgence in Electric Power Generation
** Database **

SPONSOR	PROPOSED LOCATION	SIZE TECHNOLOGY	TIMING Status - (Date indicates latest reference) In Service - Planned Date	INVESTMENT	COAL TYPE	SOURCES
PacifiCorp	Wyoming	TBD	Proposed (10/2006) In Service - 2014	TBD	Coal	1
Basin Electric Power Cooperative	Undecided ND or SD	630 MW IGCC	Feasibility Study (8/2006) In Service - TBD	$1.5 Billion	Powder River Basin Sub-Bituminous	11, 1
Xcel Energy	Undecided WI, SD, or MN	750 MW	Considering (12/2005) In Service - 2015	$1.4 Billion	Coal	1
FirstEnergy/Consol	Undecided PA or OH	TBD IGCC	Considering (3/2005) In Service - TBD	TBD	Coal	19
Dominion Resources	Undecided	2 Plants 2,150 MW (total)	Initiate - TBD In Service - TBD	~ $2.2 Billion	Coal	7, 8

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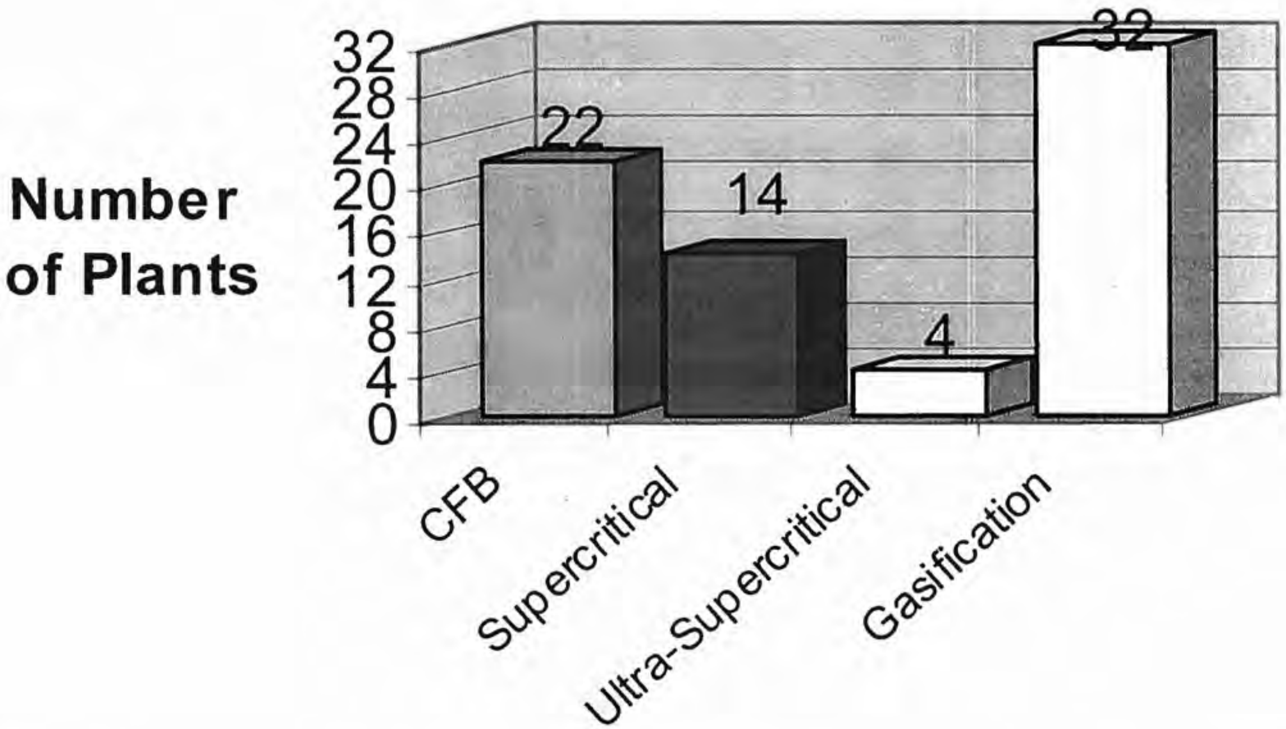
Coal's Resurgence in Electric Power Generation

Advanced Technologies



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Notes on Summarized Data

- **Number of proposed/new plants, total power, and billions invested include all proposed plants and operational plants listed in the database section of this report.**
  - Plants included in totals since the year 2000
  - Operational Plants, in green text, are included in the totals
  - Cancelled projects, in gray-strikethrough text, are NOT included in totals
- **All boiler technologies not listed are assumed to be sub critical PC boilers.**

New Coal Fired Power Plant Projects

References

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2. New Plant Construction Report, www.EnergyCentral.com
3. Western Governors Capacity Watch, http://www.westgov.org/wieb/power/capacity.htm
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5. Indiana Merchant Power Plants, http://www.state.in.us/idem/oam/permits/powerplt/map.html
6. Telephone/email Discussions with Company Representatives
7. Company Websites
8. McIlvaine Company - Utility Fax Alert & New Coal Fired Plants Report
9. Merrill Lynch, 6/4/01
10. Electricity Daily, 2/01/01
11. Coal Daily
12. Argus Energy New Generation Tracking Reports
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14. Power Jan/Feb 2002
15. Coal Age Nov/01
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17. Coal Age Magazine Online Exclusive (8/21/02)
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20. http://www.energy.ca.gov/electricity/wscc_proposed_generation.html
21. Associated Press (6/28/04), (9/8/04)
22. The Courier-Journal (9/16/04)
23. Greenwire
24. Tutuveni Newspaper of the Hopi Vol. XII No.11
25. EPA's National NSR Coal-Fired Utility Spreadsheet

EXHIBIT 2

to

PETITION FOR RECONSIDERATION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR QUALITY PROGRAM

TITLE V/STATE OPERATING PERMIT

Issue Date: May 31, 2006 Effective Date: June 1, 2006

Expiration Date: June 1, 2011

In accordance with the provisions of the Air Pollution Control Act, the Act of January 8, 1960, P.L. 2119, as amended, and 25 Pa. Code Chapter 127, the Owner, [and Operator if noted] (hereinafter referred to as permittee) identified below is authorized by the Department of Environmental Protection (Department) to operate the air emission source(s) more fully described in this permit. This Facility is subject to all terms and conditions specified in this permit. Nothing in this permit relieves the permittee from its obligations to comply with all applicable Federal, State and Local laws and regulations.

The regulatory or statutory authority for each permit condition is set forth in brackets. All terms and conditions in this permit are federally enforceable applicable requirements unless otherwise designated as "State-Only" or "non-applicable" requirements.

TITLE V Permit No: 48-00006

Federal Tax Id - Plant Code: 52-2154847-6

Owner Information

Name: RELIANT ENERGY MID ATLANTIC POWER HOLDINGS LLC
Mailing Address: 121 CHAMPION WAY
STE 200
CANONSBURG, PA 15317-5817

Plant Information

Plant: RELIANT ENERGY MID A/PORTLAND GENERATING STATION
Location: 48 Northampton County 48932 Upper Mount Bethel Township
SIC Code: 4911 Trans. & Utilities - Electric Services

Responsible Official

Name: JAMES V LOCHER
Title: VP COAL PLANT OPERATIONS
Phone: (724) 597 - 8547

Permit Contact Person

Name: TIMOTHY E MCKENZIE
Title: SR ENV SCIENTIST
Phone: (724) 597 - 8670

[Signature] ____________________
THOMAS A DILAZARO, NORTHEAST REGION AIR PROGRAM MANAGER

SECTION A. Table of Contents

SECTION A. Table of Contents

Note: These same sub-sections are repeated for each source!

SECTION G. Emission Restriction Summary.

Source Id	Source Description
031	UNIT 1 W/LOW NOX BURNERS

Emission Limit			Pollutant
0.370	Lbs/MMBTU	30-day running average	NOX
3.700	Lbs/MMBTU	30-day running average	SO2
4.000	Lbs/MMBTU	at any time	SO2
8.730	Tons	per 3-hour period	SO2
0.100	Lbs/MMBTU		TSP

Source Id	Source Description
032	UNIT 2 W/LOW NOX BURNERS

Emission Limit			Pollutant
0.580	Lbs/MMBTU	30-day runnig average	NOX
379.400	Tons/Mth	based on 0.45 lbs/MMBTU emissions	NOX
3.700	Lbs/MMBTU	30-day running average	SO2
4.000	Lbs/MMBTU	at any time	SO2
13.350	Tons	per 3-hour period	SO2
0.100	Lbs/MMBTU		TSP

Source Id	Source Description
033	AUXILIARY BOILER

Emission Limit			Pollutant
4.000	Lbs/MMBTU	over any 1-hour period	SO2
0.400	Lbs/MMBTU		TSP

Source Id	Source Description
101	COMBUSTION TURBINE 3

Emission Limit			Pollutant
500.000	PPMV		SO2
0.040	gr/DRY FT3		TSP

Source Id	Source Description
102	COMBUSTION TURBINE 4

Emission Limit			Pollutant
500.000	PPMV		SO2
0.040	gr/DRY FT3		TSP

Source Id	Source Description
103	COMBUSTION TURBINE 5 W/H2O INJECTION

Emission Limit			Pollutant
8.850	Tons/Yr	firing #2 fuel oil	CO
20.[illegible]10	Lbs/Hr	firing natural gas	CO
21.900	Lbs/Hr	firing #2 fuel oil	CO
36.430	Tons/Yr	firing natural gas*	CO
164.790	Lbs/Hr	firing natural gas	NOX
300.000	Tons/Yr	aggregate emissions	NOX
303.170	Lbs/Hr	during fuel switchover	NOX
303.170	Lbs/Hr	firing #2 fuel oil	NOX
1.980	Tons/Yr	firing natural gas*	SO2
26.160	Lbs/Day	firing natural gas	SO2
38.500	Tons/Yr	firing #2 fuel oil	SO2
2,287.200	Lbs/Day	firing #2 fuel oil	SO2

SECTION G. Emission Restriction Summary.

Source Id	Source Description		
0.020	gr/DRY FT3		TSP
3.050	Tons/Yr	firing #2 fuel oil	VOC
4.590	Lbs/Hr	firing natural gas	VOC
7.540	Lbs/Hr	firing #2 fuel oil	VOC
8.360	Tons/Yr	firing natural gas*	VOC

104 MISCELLANEOUS #2 OIL FUELED UNITS (3)

Emission Limit		Pollutant
500.000	PPMV	SO2
0.040	gr/DRY FT3	TSP

105 DRAVO HEATER

Emission Limit		Pollutant
500.000	PPMV	SO2
0.040	gr/DRY FT3	TSP

Site Emission Restriction Summary

Emission Limit	Pollutant

SECTION H. Miscellaneous.

(a) The following sources located at this facility have minor emission and no applicable emission, testing, monitoring, recordkeeping or reporting requirements:

(1) Hydrazine Solution Storage: Hydrazine is stored in drums, and are kept sealed during storage. When in use, the hydrazine is stored in solution in two (2) 400-gallon capacity storage tanks. Any losses from these tanks are due to accidental spillage.
(2) Ammonium Hydroxide Storage: Ammonium Hydroxide is stored in drums, and are kept sealed during storage. When in use, ammonium hydroxide is used to make an ammonia solution, which is stored in two (2) 400-gallon capacity storage tanks. Any losses from these tanks are due to accidental spillage.
(3) Aluminum Sulfate Storage: Aluminum Sulfate is stored in a 400 gallon capacity storage tank. Any losses from this tank are due to accidental spillage.
(4) Main Station, Combustion Turbine, ESP & Coal Transformers: These 17 transformers are sealed units which use non-PCB transformer oils. There are no expected atmospheric emissions.
(5) Dilute Sulfuric Acid Storage: This above-ground tank is a horizontal, fixed roof tank which holds a maximum of 750 gallons of 10% H2SO4 solution. Any losses from this tank are due to accidental spillage.
(6) Concentrated Sulfuric Acid Storage: This above-ground tank is a horizontal, fixed roof tank which holds a maximum of 6,000 gallons of 93% H2SO4 solution. Any losses from this tank are due to accidental spillage.
(7) Dilute Sodium Hydroxide Storage: This above-ground tank is a horizontal, fixed roof tank which holds a maximum of 5,000 gallons of 20% NaOH solution. Any losses from this tank are due to accidental spillage.
(8) Concentrated Sodium Hydroxide Storage: This above-ground tank is a horizontal, fixed roof tank which holds a maximum of 4,000 gallons of 50% NaOH solution. Any losses from this tank are due to accidental spillage.
(9) Water Treatment Dilute Caustic Storage: This above-ground tank is a horizontal, fixed roof tank which holds a maximum of 1,000 gallons of 4% NaOH solution. Any losses from this tank are due to accidental spillage.
(10) Water Treatment Dilute Acid Storage: These two (2) above-ground tanks are horizontal, fixed roof tanks which each hold a maximum of 1,000 gallons of H2SO4 solution. One tank holds a 93% H2SO4 solution, and the other holds a 5% H2SO4 solution. Any losses from these tanks are due to accidental spillage.
(11) Emergency Generator Fuel Storage: Three (3) small storage tanks (275 gallon capacity each) are used to store the diesel fuel used to supply the emergency generators.
(12) Dravo Heater Fuel Oil Storage: This above-ground tank is a horizontal, fixed roof tank which holds a maximum of 1,200 gallons of #2 fuel oil.
(13) Miscellaneous Minor Sources: These include Support Systems equipment (Hydraulic & lubricating oil storage and handling), Battery Charger emissions (emits small amounts of hydrogen gas), Vapor Extractors (to remove condensed water from the lubricating oil reservoir), various Boiler House vents (which release steam, oil vapor, carbon dioxide and small amounts of hydrogen gas), various Vented Equipment (which emit mostly steam and water vapor), and the Water Pretreatment and Wastewater Treatment & Handling (sedimentation basins and the coal run-off pond) systems.

(b) Heat input capacities listed in Section A. (Site Inventory) and Section D. (Source Level Requirements) are for informational purposes only and are not enforceable limits.

(c) The applicable emission restrictions and operating requirements for the Portland Electric Generating Station are set forth in Sections C through G of this permit. The general Title V requirements of Section B in this permit continue in full force and effect.

EXHIBIT 3

to

PETITION FOR RECONSIDERATION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR QUALITY PROGRAM

TITLE V/STATE OPERATING PERMIT

Issue Date: Effective Date:

Expiration Date:

In accordance with the provisions of the Air Pollution Control Act, the Act of January 8, 1960, P.L. 2119, as amended, and 25 Pa. Code Chapter 127, the Owner, [and Operator if noted] (hereinafter referred to as permittee) identified below is authorized by the Department of Environmental Protection (Department) to operate the air emission source(s) more fully described in this permit. This Facility is subject to all terms and conditions specified in this permit. Nothing in this permit relieves the permittee from its obligations to comply with all applicable Federal, State and Local laws and regulations.

The regulatory or statutory authority for each permit condition is set forth in brackets. All terms and conditions in this permit are federally enforceable applicable requirements unless otherwise designated as "State-Only" or "non-applicable" requirements.

TITLE V Permit No: 48-00006

Federal Tax Id - Plant Code: 52-2154847-6

Owner Information

Name: RELIANT ENERGY MID ATLANTIC POWER HOLDINGS LLC
Mailing Address: 121 CHAMPION WAY
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CANONSBURG, PA 15317-5817

Plant Information

Plant: RELIANT ENERGY MID A/PORTLAND GENERATING STATION
Location: 48 Northampton County 48932 Upper Mt Bethel Township
SIC Code: 4911 Trans. & Utilities - Electric Services

Responsible Official

Name: JAMES V LOCHER
Title: VP COAL PLANT OPERATIONS
Phone: (724) 659 - 8547

Permit Contact Person

Name: TIMOTHY E MCKENZIE
Title: SR ENV SCIENTIST
Phone: (724) 597 - 8670

[Signature] ______________________________
THOMAS A DILAZARO, NORTHEAST REGION AIR PROGRAM MANAGER

SECTION A. Table of Contents

Note: These same sub-sections are repeated for each source!

SECTION A. Table of Contents

SECTION A. Site Inventory List

Source ID	Source Name	Capacity/Throughput		Fuel/Material
031	UNIT NO. 1 W/LOW NOX BURNERS	1,657.200	MMBTU/HR	
			N/A	Bituminous
			N/A	#2 Oil
032	UNIT NO. 2 W/LOW NOX BURNERS	2,511.600	MMBTU/HR	
			N/A	Bituminous
			N/A	#2 Oil
033	AUXILIARY BOILER	12.000	MMBTU/HR	
			N/A	#2 Oil
101	COMBUSTION TURBINE NO. 3		N/A	#2 Oil
			N/A	Natural Gas
102	COMBUSTION TURBINE NO. 4		N/A	#2 Oil
			N/A	Natural Gas
103	COMBUSTION TURBINE NO. 5 W/H2O INJECTION		N/A	#2 Oil
			N/A	Natural Gas
104	MISCELLANEOUS #2 OIL FUELED UNITS (3)			
105	DRAVO HEATER			
106	UNDERGROUND GASOLINE STORAGE TANK			
107	MAIN FUEL OIL STORAGE TANKS (3)			
108	THREE (3) SMALL DIESEL STORAGE TANKS			
P01	FUGITIVE DUSTS - PLANT HAUL ROADS			
P02	FUGITIVE DUSTS - COAL STORAGE & HANDLING			
P03	FUGITIVE DUSTS - ASH DISPOSAL			
C01	UNIT NO. 1 ESP			
C02	UNIT NO. 2 ESP			
CF1	RAILCAR UNLOADING ENCLOSURE			
CF2	BOILER HOUSE FUEL HOPPER ENCLOSURE			
CF3	ASH TRANSFER ENCLOSURES			
CF4	CRUSHER/BREAKER ENCLOSURES			
#25	NATURAL GAS LINE & HEATER			
001	MAIN FUEL OIL STORAGE TANKS (3)			
002	STATION COAL STOCKPILE			
S01	UNIT NO. 1 STACK			
S02	UNIT NO. 2 STACK			
S03	TURBINE NO. 3 STACK			
S04	TURBINE NO. 4 STACK			
S05	TURBINE NO. 5 STACK			
S06	AUXILLIARY BOILER STACK			
Z01	PAVED ROAD DUST EMISSIONS			
Z02	FUGITIVE COAL DUST EMISSIONS			
Z03	ASH DISPOSAL DUST EMISSIONS			
Z04	FUGITVE COMBUSTION LOSSES			
Z05	DRAVO HEATER EMISSIONS			
Z06	GASOLINE TANK FUGITIVES			
Z07	OIL TANK FUGITIVES			
Z08	DIESEL STORAGE FUGITIVES			

PERMIT MAPS

SECTION B. General Title V Requirements

#001 [25 Pa. Code § 121.1]

Definitions

Words and terms that are not otherwise defined in this permit shall have the meanings set forth in Section 3 of the Air Pollution Control Act (35 P.S. § 4003) and 25 Pa. Code § 121.1.

#002 [25 Pa. Code § 127.512(c)(4)]

Property Rights

This permit does not convey property rights of any sort, or any exclusive privileges.

#003 [25 Pa. Code § 127.446(a) and (c)]

Permit Expiration

This operating permit is issued for a fixed term of five (5) years and shall expire on the date specified on Page 1 of this permit. The terms and conditions of the expired permit shall automatically continue pending issuance of a new Title V permit, provided the permittee has submitted a timely and complete application and paid applicable fees required under 25 Pa. Code Chapter 127, Subchapter I and the Department is unable, through no fault of the permittee, to issue or deny a new permit before the expiration of the previous permit. An application is complete if it contains sufficient information to begin processing the application, has the applicable sections completed and has been signed by a responsible official.

#004 [25 Pa. Code §§ 127.412, 127.413, 127.414, 127.446(e) & 127.503]

Permit Renewal

(a) An application for the renewal of the Title V permit shall be submitted to the Department at least six (6) months, and not more than 18 months, before the expiration date of this permit. The renewal application is timely if a complete application is submitted to the Department's Regional Air Manager within the timeframe specified in this permit condition.

(b) The application for permit renewal shall include the current permit number, the appropriate permit renewal fee, a description of any permit revisions and off-permit changes that occurred during the permit term, and any applicable requirements that were promulgated and not incorporated into the permit during the permit term.

(c) The renewal application shall also include submission of proof that the local municipality and county, in which the facility is located, have been notified in accordance with 25 Pa. Code § 127.413. The application for renewal of the Title V permit shall also include submission of compliance review forms which have been used by the permittee to update information submitted in accordance with either 25 Pa. Code § 127.412(b) or § 127.412(j).

(d) The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall submit such supplementary facts or corrected information during the permit renewal process. The permittee shall also provide additional information as necessary to address any requirements that become applicable to the source after the date a complete renewal application was submitted but prior to release of a draft permit.

#005 [25 Pa. Code §§ 127.450(a)(4) & 127.464(a)]

Transfer of Ownership or Operational Control

(a) In accordance with 25 Pa. Code § 127.450(a)(4), a change in ownership or operational control of the source shall be treated as an administrative amendment if:

(1) The Department determines that no other change in the permit is necessary;

(2) A written agreement has been submitted to the Department identifying the specific date of the transfer of permit responsibility, coverage and liability between the current and the new permittee; and,

(3) A compliance review form has been submitted to the Department and the permit transfer has been approved by the Department.

(b) In accordance with 25 Pa. Code § 127.464(a), this permit may not be transferred to another person except in cases of transfer-of-ownership which are documented and approved to the satisfaction of the Department.

SECTION B. General Title V Requirements

#006 [25 Pa. Code § 127.513, 35 P.S. § 4008 and § 114 of the CAA]

Inspection and Entry

(a) Upon presentation of credentials and other documents as may be required by law for inspection and entry purposes, the permittee shall allow the Department of Environmental Protection or authorized representatives of the Department to perform the following:

(1) Enter at reasonable times upon the permittee's premises where a Title V source is located or emissions related activity is conducted, or where records are kept under the conditions of this permit;

(2) Have access to and copy or remove, at reasonable times, records that are kept under the conditions of this permit;

(3) Inspect at reasonable times, facilities, equipment including monitoring and air pollution control equipment, practices, or operations regulated or required under this permit;

(4) Sample or monitor, at reasonable times, substances or parameters, for the purpose of assuring compliance with the permit or applicable requirements as authorized by the Clean Air Act, the Air Pollution Control Act, or the regulations promulgated under the Acts.

(b) Pursuant to 35 P.S. § 4008, no person shall hinder, obstruct, prevent or interfere with the Department or its personnel in the performance of any duty authorized under the Air Pollution Control Act.

(c) Nothing in this permit condition shall limit the ability of the EPA to inspect or enter the premises of the permittee in accordance with Section 114 or other applicable provisions of the Clean Air Act.

#007 [25 Pa. Code §§ 127.25, 127.444, & 127.512(c)(1)]

Compliance Requirements

(a) The permittee shall comply with the conditions of this permit. Noncompliance with this permit constitutes a violation of the Clean Air Act and the Air Pollution Control Act and is grounds for one (1) or more of the following:

(1) Enforcement action

(2) Permit termination, revocation and reissuance or modification

(3) Denial of a permit renewal application

(b) A person may not cause or permit the operation of a source, which is subject to 25 Pa. Code Article III, unless the source(s) and air cleaning devices identified in the application for the plan approval and operating permit and the plan approval issued to the source are operated and maintained in accordance with specifications in the applications and the conditions in the plan approval and operating permit issued by the Department. A person may not cause or permit the operation of an air contamination source subject to 25 Pa. Code Chapter 127 in a manner inconsistent with good operating practices.

(c) For purposes of Sub-condition (b) of this permit condition, the specifications in applications for plan approvals and operating permits are the physical configurations and engineering design details which the Department determines are essential for the permittee's compliance with the applicable requirements in this Title V permit. Nothing in this sub-condition shall be construed to create an independent affirmative duty upon the permittee to obtain a predetermination from the Department for physical configuration or engineering design detail changes made by the permittee.

#008 [25 Pa. Code § 127.512(c)(2)]

Need to Halt or Reduce Activity Not a Defense

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

#009 [25 Pa. Code §§ 127.411(d) & 127.512(c)(5)]

Duty to Provide Information

(a) The permittee shall furnish to the Department, within a reasonable time, information that the Department may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to

SECTION B. General Title V Requirements

determine compliance with the permit.

(b) Upon request, the permittee shall also furnish to the Department copies of records that the permittee is required to keep by this permit, or for information claimed to be confidential, the permittee may furnish such records directly to the Administrator of EPA along with a claim of confidentiality.

#010 [25 Pa. Code §§ 127.463, 127.512(c)(3) & 127.542]

Reopening and Revising the Title V Permit for Cause

(a) This Title V permit may be modified, revoked, reopened and reissued or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay a permit condition.

(b) This permit may be reopened, revised and reissued prior to expiration of the permit under one or more of the following circumstances:

(1) Additional applicable requirements under the Clean Air Act or the Air Pollution Control Act become applicable to a Title V facility with a remaining permit term of three (3) or more years prior to the expiration date of this permit. The Department will revise the permit as expeditiously as practicable but not later than 18 months after promulgation of the applicable standards or regulations. No such revision is required if the effective date of the requirement is later than the expiration date of this permit, unless the original permit or its terms and conditions has been extended.

(2) Additional requirements, including excess emissions requirements, become applicable to an affected source under the acid rain program. Upon approval by the Administrator of EPA, excess emissions offset plans for an affected source shall be incorporated into the permit.

(3) The Department or the EPA determines that this permit contains a material mistake or inaccurate statements were made in establishing the emissions standards or other terms or conditions of this permit.

(4) The Department or the Administrator of EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

(c) Proceedings to revise this permit shall follow the same procedures which apply to initial permit issuance and shall affect only those parts of this permit for which cause to revise exists. The revision shall be made as expeditiously as practicable.

(d) Regardless of whether a revision is made in accordance with (b)(1) above, the permittee shall meet the applicable standards or regulations promulgated under the Clean Air Act within the time frame required by standards or regulations.

#011 [25 Pa. Code § 127.543]

Reopening a Title V Permit for Cause by EPA

As required by the Clean Air Act and regulations adopted thereunder, this permit may be modified, reopened and reissued, revoked or terminated for cause by EPA in accordance with procedures specified in 25 Pa. Code § 127.543.

#012 [25 Pa. Code § 127.541]

Significant Operating Permit Modifications

When permit modifications during the term of this permit do not qualify as minor permit modifications or administrative amendments, the permittee shall submit an application for significant Title V permit modifications in accordance with 25 Pa. Code § 127.541.

#013 [25 Pa. Code §§ 121.1 & 127.462]

Minor Operating Permit Modifications

(a) The permittee may make minor operating permit modifications (as defined in 25 Pa. Code § 121.1) in accordance with 25 Pa. Code § 127.462.

(b) Unless precluded by the Clean Air Act or the regulations thereunder, the permit shield described in 25 Pa. Code § 127.516 (relating to permit shield) shall extend to an operational flexibility change authorized by 25 Pa. Code § 127.462.

SECTION B. General Title V Requirements

#014 [25 Pa. Code § 127.450]

Administrative Operating Permit Amendments

(a) The permittee may request administrative operating permit amendments, as defined in 25 Pa. Code § 127.450(a), according to procedures specified in § 127.450. Administrative amendments are not authorized for any amendment precluded by the Clean Air Act or the regulations thereunder from being processed as an administrative amendment.

(b) Upon taking final action granting a request for an administrative permit amendment in accordance with § 127.450(c), the Department will allow coverage under 25 Pa. Code § 127.516 (relating to permit shield) for administrative permit amendments which meet the relevant requirements of 25 Pa. Code Article III, unless precluded by the Clean Air Act or the regulations thereunder.

#015 [25 Pa. Code § 127.512(b)]

Severability Clause

The provisions of this permit are severable, and if any provision of this permit is determined by the Environmental Hearing Board or a court of competent jurisdiction to be invalid or unenforceable, such a determination will not affect the remaining provisions of this permit.

#016 [25 Pa. Code §§ 127.704, 127.705 & 127.707]

Fee Payment

(a) The permittee shall pay fees to the Department in accordance with the applicable fee schedules in 25 Pa. Code Chapter 127, Subchapter I (relating to plan approval and operating permit fees).

(b) Emission Fees. The permittee shall, on or before September 1st of each year, pay applicable annual Title V emission fees for emissions occurring in the previous calendar year as specified in 25 Pa. Code § 127.705. The permittee is not required to pay an emission fee for emissions of more than 4,000 tons of each regulated pollutant emitted from the facility.

(c) As used in this permit condition, the term "regulated pollutant" is defined as a VOC, each pollutant regulated under Sections 111 and 112 of the Clean Air Act and each pollutant for which a National Ambient Air Quality Standard has been promulgated, except that carbon monoxide is excluded.

(d) Late Payment. Late payment of emission fees will subject the permittee to the penalties prescribed in 25 Pa. Code § 127.707 and may result in the suspension or termination of the Title V permit. The permittee shall pay a penalty of fifty percent (50%) of the fee amount, plus interest on the fee amount computed in accordance with 26 U.S.C.A. § 6621(a)(2) from the date the emission fee should have been paid in accordance with the time frame specified in 25 Pa. Code § 127.705(c).

(e) The permittee shall pay an annual operating permit administration fee according to the fee schedule established in 25 Pa. Code § 127.704(c) if the facility, identified in Subparagraph (iv) of the definition of the term "Title V facility" in 25 Pa. Code § 121.1, is subject to Title V after the EPA Administrator completes a rulemaking requiring regulation of those sources under Title V of the Clean Air Act.

(f) This permit condition does not apply to a Title V facility which qualifies for exemption from emission fees under 35 P.S. § 4006.3(f).

#017 [25 Pa. Code §§ 127.14(b) & 127.449]

Authorization for De Minimis Emission Increases

(a) This permit authorizes de minimis emission increases from a new or existing source in accordance with 25 Pa. Code §§ 127.14 and 127.449 without the need for a plan approval or prior issuance of a permit modification. The permittee shall provide the Department with seven (7) days prior written notice before commencing any de minimis emissions increase that would result from either: (1) a physical change of minor significance under § 127.14(c)(1); or (2) the construction, installation, modification or reactivation of an air contamination source. The written notice shall:

(1) Identify and describe the pollutants that will be emitted as a result of the de minimis emissions increase.

(2) Provide emission rates expressed in tons per year and in terms necessary to establish compliance consistent with any applicable requirement.

SECTION B. General Title V Requirements

The Department may disapprove or condition de minimis emission increases at any time.

(b) Except as provided below in (c) and (d) of this permit condition, the permittee is authorized during the term of this permit to make de minimis emission increases (expressed in tons per year) up to the following amounts without the need for a plan approval or prior issuance of a permit modification:

(1) Four tons of carbon monoxide from a single source during the term of the permit and 20 tons of carbon monoxide at the facility during the term of the permit.

(2) One ton of NOx from a single source during the term of the permit and 5 tons of NOx at the facility during the term of the permit.

(3) One and six-tenths tons of the oxides of sulfur from a single source during the term of the permit and 8.0 tons of oxides of sulfur at the facility during the term of the permit.

(4) Six-tenths of a ton of PM10 from a single source during the term of the permit and 3.0 tons of PM10 at the facility during the term of the permit. This shall include emissions of a pollutant regulated under Section 112 of the Clean Air Act unless precluded by the Clean Air Act or 25 Pa. Code Article III.

(5) One ton of VOCs from a single source during the term of the permit and 5.0 tons of VOCs at the facility during the term of the permit. This shall include emissions of a pollutant regulated under Section 112 of the Clean Air Act unless precluded by the Clean Air Act or 25 Pa. Code Article III.

(c) In accordance with § 127.14, the permittee may install the following minor sources without the need for a plan approval:

(1) Air conditioning or ventilation systems not designed to remove pollutants generated or released from other sources.

(2) Combustion units rated at 2,500,000 or less Btu per hour of heat input.

(3) Combustion units with a rated capacity of less than 10,000,000 Btu per hour heat input fueled by natural gas supplied by a public utility, liquefied petroleum gas or by commercial fuel oils which are No. 2 or lighter, viscosity less than or equal to 5.82 c St, and which meet the sulfur content requirements of 25 Pa. Code § 123.22 (relating to combustion units). For purposes of this permit, commercial fuel oil shall be virgin oil which has no reprocessed, recycled or waste material added.

(4) Space heaters which heat by direct heat transfer.

(5) Laboratory equipment used exclusively for chemical or physical analysis.

(6) Other sources and classes of sources determined to be of minor significance by the Department.

(d) This permit does not authorize de minimis emission increases if the emissions increase would cause one or more of the following:

(1) Increase the emissions of a pollutant regulated under Section 112 of the Clean Air Act except as authorized in Subparagraphs (b)(4) and (5) of this permit condition.

(2) Subject the facility to the prevention of significant deterioration requirements in 25 Pa. Code Chapter 127, Subchapter D and/or the new source review requirements in Subchapter E.

(3) Violate any applicable requirement of the Air Pollution Control Act, the Clean Air Act, or the regulations promulgated under either of the acts.

(4) Changes which are modifications under any provision of Title I of the Clean Air Act and emission increases which would exceed the allowable emissions level (expressed as a rate of emissions or in terms of total emissions) under the Title V permit.

(e) Unless precluded by the Clean Air Act or the regulations thereunder, the permit shield described in 25 Pa. Code §

SECTION B. General Title V Requirements

127.516 (relating to permit shield) applies to de minimis emission increases and the installation of minor sources made pursuant to this permit condition.

(f) Emissions authorized under this permit condition shall be included in the monitoring, recordkeeping and reporting requirements of this permit.

(g) Except for de minimis emission increases allowed under this permit, 25 Pa. Code § 127.449, or sources and physical changes meeting the requirements of 25 Pa. Code § 127.14, the permittee is prohibited from making physical changes or engaging in activities that are not specifically authorized under this permit without first applying for a plan approval. In accordance with § 127.14(b), a plan approval is not required for the construction, modification, reactivation, or installation of the sources creating the de minimis emissions increase.

(h) The permittee may not meet de minimis emission threshold levels by offsetting emission increases or decreases at the same source.

#018 [25 Pa. Code §§ 127.11a & 127.215]
Reactivation of Sources

(a) The permittee may reactivate a source at the facility that has been out of operation or production for at least one year, but less than or equal to five (5) years, if the source is reactivated in accordance with the requirements of 25 Pa. Code §§ 127.11a and 127.215. The reactivated source will not be considered a new source.

(b) A source which has been out of operation or production for more than five (5) years but less than 10 years may be reactivated and will not be considered a new source if the permittee satisfies the conditions specified in 25 Pa. Code § 127.11a(b).

#019 [25 Pa. Code §§ 121.9 & 127.216]
Circumvention

(a) The owner of this Title V facility, or any other person, may not circumvent the new source review requirements of 25 Pa. Code Chapter 127, Subchapter E by causing or allowing a pattern of ownership or development, including the phasing, staging, delaying or engaging in incremental construction, over a geographic area of a facility which, except for the pattern of ownership or development, would otherwise require a permit or submission of a plan approval application.

(b) No person may permit the use of a device, stack height which exceeds good engineering practice stack height, dispersion technique or other technique which, without resulting in reduction of the total amount of air contaminants emitted, conceals or dilutes an emission of air contaminants which would otherwise be in violation of this permit, the Air Pollution Control Act or the regulations promulgated thereunder, except that with prior approval of the Department, the device or technique may be used for control of malodors.

#020 [25 Pa. Code §§ 127.402(d) & 127.513(1)]
Submissions

(a) Reports, test data, monitoring data, notifications and requests for renewal of the permit shall be submitted to the:

Regional Air Program Manager
PA Department of Environmental Protection
(At the address given on the permit transmittal letter,
or otherwise notified)

(b) Any report or notification for the EPA Administrator or EPA Region III should be addressed to:

Air Enforcement Branch (3AP12)
United States Environmental Protection Agency
Region 3
1650 Arch Street
Philadelphia, PA 19103-2029

(c) An application, form, report or compliance certification submitted pursuant to this permit condition shall contain certification by a responsible official as to truth, accuracy, and completeness as required under 25 Pa. Code § 127.402(d). Unless otherwise required by the Clean Air Act or regulations adopted thereunder, this certification and any other certification required pursuant to this permit shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

#021 [25 Pa. Code §§ 127.441(c) & 127.463(e); Chapter 139; & 114(a)(3), 504(b) of the CAA]

Sampling, Testing and Monitoring Procedures

(a) The permittee shall perform the emissions monitoring and analysis procedures or test methods for applicable requirements of this Title V permit. In addition to the sampling, testing and monitoring procedures specified in this permit, the Permittee shall comply with any additional applicable requirements promulgated under the Clean Air Act after permit issuance regardless of whether the permit is revised.

(b) The sampling, testing and monitoring required under the applicable requirements of this permit, shall be conducted in accordance with the requirements of 25 Pa. Code Chapter 139 unless alternative methodology is required by the Clean Air Act (including §§ 114(a)(3) and 504(b)) and regulations adopted thereunder.

#022 [25 Pa. Code §§ 127.511 & Chapter 135]

Recordkeeping Requirements

(a) The permittee shall maintain and make available, upon request by the Department, records of required monitoring information that include the following:

(1) The date, place (as defined in the permit) and time of sampling or measurements.

(2) The dates the analyses were performed.

(3) The company or entity that performed the analyses.

(4) The analytical techniques or methods used.

(5) The results of the analyses.

(6) The operating conditions as existing at the time of sampling or measurement.

(b) The permittee shall retain records of the required monitoring data and supporting information for at least five (5) years from the date of the monitoring sample, measurement, report or application. Supporting information includes the calibration data and maintenance records and original strip-chart recordings for continuous monitoring instrumentation, and copies of reports required by the permit.

(c) The permittee shall maintain and make available to the Department upon request, records including computerized records that may be necessary to comply with the reporting, recordkeeping and emission statement requirements in 25 Pa. Code Chapter 135 (relating to reporting of sources). In accordance with 25 Pa. Code Chapter 135, § 135.5, such records may include records of production, fuel usage, maintenance of production or pollution control equipment or other information determined by the Department to be necessary for identification and quantification of potential and actual air contaminant emissions. If direct recordkeeping is not possible or practical, sufficient records shall be kept to provide the needed information by indirect means.

#023 [25 Pa. Code §§ 127.411(d), 127.442, 127.463(e) & 127.511(c)]

Reporting Requirements

(a) The permittee shall comply with the reporting requirements for the applicable requirements specified in this Title V permit. In addition to the reporting requirements specified herein, the permittee shall comply with any additional applicable reporting requirements promulgated under the Clean Air Act after permit issuance regardless of whether the permit is revised.

(b) Pursuant to 25 Pa. Code § 127.511(c), the permittee shall submit reports of required monitoring at least every six (6) months unless otherwise specified in this permit. Instances of deviations (as defined in 25 Pa. Code § 121.1) from permit requirements shall be clearly identified in the reports. The reporting of deviations shall include the probable cause of the deviations and corrective actions or preventative measures taken, except that sources with continuous emission monitoring systems shall report according to the protocol established and approved by the Department for the source.

SECTION B. General Title V Requirements

The required reports shall be certified by a responsible official.

(c) Every report submitted to the Department under this permit condition shall comply with the submission procedures specified in Section B, Condition #020(c) of this permit.

(d) Any records, reports or information obtained by the Department or referred to in a public hearing shall be made available to the public by the Department except for such records, reports or information for which the permittee has shown cause that the documents should be considered confidential and protected from disclosure to the public under Section 4013.2 of the Air Pollution Control Act and consistent with Sections 112(d) and 114(c) of the Clean Air Act and 25 Pa. Code § 127.411(d). The permittee may not request a claim of confidentiality for any emissions data generated for the Title V facility.

#024 [25 Pa. Code § 127.513]

Compliance Certification

(a) One year after the date of issuance of the Title V permit, and each year thereafter, unless specified elsewhere in the permit, the permittee shall submit to the Department and EPA Region III a certificate of compliance with the terms and conditions in this permit, for the previous year, including the emission limitations, standards or work practices. This certification shall include:

(1) The identification of each term or condition of the permit that is the basis of the certification.

(2) The compliance status.

(3) The methods used for determining the compliance status of the source, currently and over the reporting period.

(4) Whether compliance was continuous or intermittent.

(b) The compliance certification should be postmarked or hand-delivered within thirty days of each anniversary date of the date of issuance to the Department and EPA in accordance with the submission requirements specified in Condition #020 of this section.

#025 [25 Pa. Code § 127.3]

Operational Flexibility

(a) The permittee is authorized to make changes within the Title V facility in accordance with the following provisions in 25 Pa. Code Chapter 127 which implement the operational flexibility requirements of Section 502(b)(10) of the Clean Air Act and Section 6.1(i) of the Air Pollution Control Act:

(1) Section 127.14 (relating to exemptions)

(2) Section 127.447 (relating to alternative operating scenarios)

(3) Section 127.448 (relating to emissions trading at facilities with Federally enforceable emissions caps)

(4) Section 127.449 (relating to de minimis emission increases)

(5) Section 127.450 (relating to administrative operating permit amendments)

(6) Section 127.462 (relating to minor operating permit amendments)

(7) Subchapter H (relating to general plan approvals and operating permits)

(b) Unless precluded by the Clean Air Act or the regulations adopted thereunder, the permit shield authorized under 25 Pa. Code § 127.516 shall extend to operational flexibility changes made at this Title V facility pursuant to this permit condition and other applicable operational flexibility terms and conditions of this permit.

#026 [25 Pa. Code §§ 127.441(d), 127.512(i) and 40 CFR Part 68]

Risk Management

(a) If required by Section 112(r) of the Clean Air Act, the permittee shall develop and implement an accidental release program consistent with requirements of the Clean Air Act, 40 CFR Part 68 (relating to chemical accident prevention provisions) and the Federal Chemical Safety Information, Site Security and Fuels Regulatory Relief Act (P.L. 106-40).

(b) The permittee shall prepare and implement a Risk Management Plan (RMP) which meets the requirements of Section 112(r) of the Clean Air Act, 40 CFR Part 68 and the Federal Chemical Safety Information, Site Security and Fuels Regulatory Relief Act when a regulated substance listed in 40 CFR § 68.130 is present in a process in more than the listed threshold quantity at the Title V facility. The permittee shall submit the RMP to the federal Environmental Protection Agency according to the following schedule and requirements:

(1) The permittee shall submit the first RMP to a central point specified by EPA no later than the latest of the following:

(i) Three years after the date on which a regulated substance is first listed under § 68.130; or,

(ii) The date on which a regulated substance is first present above a threshold quantity in a process.

(2) The permittee shall submit any additional relevant information requested by the Department or EPA concerning the RMP and shall make subsequent submissions of RMPs in accordance with 40 CFR § 68.190.

(3) The permittee shall certify that the RMP is accurate and complete in accordance with the requirements of 40 CFR Part 68, including a checklist addressing the required elements of a complete RMP.

(c) As used in this permit condition, the term "process" shall be as defined in 40 CFR § 68.3. The term "process" means any activity involving a regulated substance including any use, storage, manufacturing, handling, or on-site movement of such substances or any combination of these activities. For purposes of this definition, any group of vessels that are interconnected, or separate vessels that are located such that a regulated substance could be involved in a potential release, shall be considered a single process.

(d) If the Title V facility is subject to 40 CFR Part 68, as part of the certification required under this permit, the permittee shall:

(1) Submit a compliance schedule for satisfying the requirements of 40 CFR Part 68 by the date specified in 40 CFR § 68.10(a); or,

(2) Certify that the Title V facility is in compliance with all requirements of 40 CFR Part 68 including the registration and submission of the RMP.

(e) If the Title V facility is subject to 40 CFR Part 68, the permittee shall maintain records supporting the implementation of an accidental release program for five (5) years in accordance with 40 CFR § 68.200.

(f) When the Title V facility is subject to the accidental release program requirements of Section 112(r) of the Clean Air Act and 40 CFR Part 68, appropriate enforcement action will be taken by the Department if:

(1) The permittee fails to register and submit the RMP or a revised plan pursuant to 40 CFR Part 68.

(2) The permittee fails to submit a compliance schedule or include a statement in the compliance certification required under Condition #24 of Section B of this Title V permit that the Title V facility is in compliance with the requirements of Section 112(r) of the Clean Air Act, 40 CFR Part 68, and 25 Pa. Code § 127.512(i).

#027 [25 Pa. Code § 127.512(e)]

Approved Economic Incentives and Emission Trading Programs

No permit revision shall be required under approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this Title V permit.

#028 [25 Pa. Code §§ 127.516, 127.450(d), 127.449(f) & 127.462(g)]

Permit Shield

(a) The permittee's compliance with the conditions of this permit shall be deemed in compliance with applicable requirements (as defined in 25 Pa. Code § 121.1) as of the date of permit issuance if either of the following applies:

(1) The applicable requirements are included and are specifically identified in this permit.

SECTION B. General Title V Requirements

(2) The Department specifically identifies in the permit other requirements that are not applicable to the permitted facility or source.

(b) Nothing in 25 Pa. Code § 127.516 or the Title V permit shall alter or affect the following:

(1) The provisions of Section 303 of the Clean Air Act, including the authority of the Administrator of the EPA provided thereunder.

(2) The liability of the permittee for a violation of an applicable requirement prior to the time of permit issuance.

(3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act.

(4) The ability of the EPA to obtain information from the permittee under Section 114 of the Clean Air Act.

(c) Unless precluded by the Clean Air Act or regulations thereunder, final action by the Department on minor or significant permit modifications, and operational flexibility changes shall be covered by the permit shield. Upon taking final action granting a request for an administrative permit amendment, the Department will allow coverage of the amendment by the permit shield in § 127.516 for administrative amendments which meet the relevant requirements of 25 Pa. Code Article III.

(d) The permit shield authorized under § 127.516 is in effect for the permit terms and conditions in this Title V permit, including administrative operating permit amendments and minor operating permit modifications.

SECTION D. Source Level Requirements

Source ID: 031 Source Name: UNIT NO. 1 W/LOW NOX BURNERS

Source Capacity/Throughput: 1,657.200 MMBTU/HR
N/A Bituminous
N/A #2 Oil

Conditions for this source occur in the following groups: GROUP 1
GROUP 3
GROUP 4

CU 031 → CNTL C01 → STAC S01
FML 001 → CU 031
FML 002 → CU 031

I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The concentration of Nitrogen Oxides (NOx) in the emissions from Source 031 may not exceed 0.3700 Pounds per Million BTU of Nitrogen Oxides (on a 30-day running average) as determined by the unit's EPA 40 CFR Part 75 and PADEP certified CEMS.

[Authority for this condition is also derived from 25 Pa. Code, Section 129.92]

 # 002 [25 Pa. Code §127.441]
Operating permit terms and conditions.

In order to protect the SO2 NAAQS, as determined by a Department-approved compliance demostration, emissions of sulfur oxides (expressed as SO2) from Unit No. 1 may not exceed 8.73 Tons per 3-hour period as determined by the unit's EPA 40 CFR Part 75 and PADEP certified CEMS.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

 # 003 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

The permittee shall, on a daily basis, monitor and record the hours of operation of this boiler.

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

SECTION D. Source Level Requirements

Source ID: 032 Source Name: UNIT NO. 2 W/LOW NOX BURNERS

Source Capacity/Throughput: 2,511.600 MMBTU/HR
N/A Bituminous
N/A #2 Oil

Conditions for this source occur in the following groups: GROUP 1
GROUP 3
GROUP 4

CU 032 → CNTL C02 → STAC S02

FML 001 → CU 032

FML 002 → CU 032

I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §127.441]

Operating permit terms and conditions.

The concentration of Nitrogen Oxides (NOx) in the emissions from Source 032 may not exceed the following limitations, as determined by the unit's EPA 40 CFR Part 75 and PADEP certified CEMS:

(a) On a 30-day rolling average, the emissions shall not exceed 0.5800 Pounds per Million BTU of Nitrogen Oxides.

(b) As a monthly maximum emission limit, not to be exceeded at any time, the emissions shall not exceed 379.4 tons per month (based on 0.45 Pounds per Million BTU of NOx emitted).

[Authority for this condition is also derived from 25 Pa. Code, Section 129.92]

 # 002 [25 Pa. Code §127.441]

Operating permit terms and conditions.

In order to protect the SO2 NAAQS, as determined by a Department-approved compliance demostration, emissions of sulfur oxides (expressed as SO2) from Unit No. 2 may not exceed 13.35 Tons per 3-hour period as determined by the unit's EPA 40 CFR Part 75 and PADEP certified CEMS.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

 # 003 [25 Pa. Code §127.511]

Monitoring and related recordkeeping and reporting requirements.

The permittee shall, on a daily basis, monitor and record the hours of operation of this boiler.

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

SECTION E. Source Group Restrictions.

Group Name: GROUP 1

Group Description: MAIN BOILERS

Sources included in this group:

ID	Name
031	UNIT NO. 1 W/LOW NOX BURNERS
032	UNIT NO. 2 W/LOW NOX BURNERS

I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.11]

Combustion units

The concentration of particulate matter (expressed as TSP) in the emissions from each boiler may not exceed 0.1000 Pounds per Million BTU of Total Suspended Particulate.

 # 002 [25 Pa. Code §123.22]

Combustion units

The concentration of Sulfur Oxides (expressed as SO2) in the emissions from each boiler may not exceed 3.7000 Pounds per Million BTU of Sulfur Dioxide (based on a 30-day running average).

 # 003 [40 CFR Part 52 Approval And Promulgation of Implementation Plans §40 CFR 52.2020]

Subpart NN--Pennsylvania
Identification of plan.

No person may permit the emission ito the outdoor atmosphere of sulfur oxides, expressed as SO2, from these combustion units in excess of 4.0 Lbs/MMBtu.

Fuel Restriction(s).

 # 004 [25 Pa. Code §127.444]

Compliance requirements.

These sources may combust only coal, #2 fuel oil and cleaning chemical rinse water.

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

 # 005 [25 Pa. Code §127.511]
Monitoring and related recordkeeping and reporting requirements.

[Authority for this condition is also derived from 40 CFR Part 64, regarding Compliance Assurance Monitoring (CAM)]

(a) Data Representativeness

(1) The % opacity measured by the COM is proportional to the amount of particulate matter (TSP) in the exhaust stream. The accuracy of the COM shall be verified annually by methods specified in the most recent version of the Department of Environmental Protection's CEM Manual. Opacity shall be further correlated to the mass emission rate through an approved particulate testing program taken during routine, normal operations in a full daily cycle.

(2) The % opacity will also act as a direct indication of the integrity of the electrostatic precipitator and the various components involved. Further, the precipitator integrity is representative of the particulate emission rate. The COM is located in the exhaust stack after the precipitator outlet. The COM shall have a minimum accuracy as specified in the latest edition of PADEP's Continuous Source Monitoring Manual.

(b) Verification of Operational Status

The operation of the COM shall be verified by a power "on" indicator light in the control center, the presence of a non-zero

SECTION G. Emission Restriction Summary.

Dep Id	Source Description
031	UNIT NO. 1 W/LOW NOX BURNERS

Emission Limit			Pollutant
0.370	Lbs/MMBTU	30-day running average	NOX
0.100	Lbs/MMBTU		P000
3.700	Lbs/MMBTU	30-day running average	SO2
4.000	Lbs/MMBTU	at any time	SOX
8.730	Tons	per 3-hour period	SOX

Dep Id	Source Description
032	UNIT NO. 2 W/LOW NOX BURNERS

Emission Limit			Pollutant
0.580	Lbs/MMBTU	30-day runnig average	NOX
379.400	Tons/Mth	based on 0.45 lbs/MMBTU emissions	NOX
0.100	Lbs/MMBTU		P000
3.700	Lbs/MMBTU	30-day running average	SO2
4.000	Lbs/MMBTU	at any time	SOX
13.350	Tons	per 3-hour period	SOX

Dep Id	Source Description
033	AUXILIARY BOILER

Emission Limit			Pollutant
0.400	Lbs/MMBTU		P000
4.000	Lbs/MMBTU	over any 1-hour period	SO2

Dep Id	Source Description
101	COMBUSTION TURBINE NO. 3

Emission Limit			Pollutant
0.040	gr/DRY FT3		P000
500.000	PPMV		SO2

Dep Id	Source Description
102	COMBUSTION TURBINE NO. 4

Emission Limit			Pollutant
0.040	gr/DRY FT3		P000
500.000	PPMV		SO2

Dep Id	Source Description
103	COMBUSTION TURBINE NO. 5 W/H2O INJECTION

Emission Limit			Pollutant
8.850	Tons/Yr	firing #2 fuel oil	CO
20.010	Lbs/Hr	firing natural gas	CO
21.900	Lbs/Hr	firing #2 fuel oil	CO
36.430	Tons/Yr	firing natural gas*	CO
164.790	Lbs/Hr	firing natural gas	NOX
300.000	Tons/Yr	aggregate emissions	NOX
303.170	Lbs/Hr	during fuel switchover	NOX
303.170	Lbs/Hr	firing #2 fuel oil	NOX
0.020	gr/DRY FT3		P000
1.980	Tons/Yr	firing natural gas*	SO2
26.160	Lbs/Day	firing natural gas	SO2
38.500	Tons/Yr	firing #2 fuel oil	SO2
2,287.200	Lbs/Day	firing #2 fuel oil	SO2

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR QUALITY PROGRAM

TITLE V/STATE OPERATING PERMIT

Issue Date: Effective Date:

Expiration Date:

In accordance with the provisions of the Air Pollution Control Act, the Act of January 8, 1960, P.L. 2119, as amended, and 25 Pa. Code Chapter 127, the Owner, [and Operator if noted] (hereinafter referred to as permittee) identified below is authorized by the Department of Environmental Protection (Department) to operate the air emission source(s) more fully described in this permit. This Facility is subject to all terms and conditions specified in this permit. Nothing in this permit relieves the permittee from its obligations to comply with all applicable Federal, State and Local laws and regulations.

The regulatory or statutory authority for each permit condition is set forth in brackets. All terms and conditions in this permit are federally enforceable applicable requirements unless otherwise designated as "State-Only" or "non-applicable" requirements.

TITLE V Permit No: 48-00006

Federal Tax Id - Plant Code: 52-2154847-6

Owner Information

Name: RELIANT ENERGY MID ATLANTIC POWER HOLDINGS LLC
Mailing Address: 121 CHAMPION WAY
STE 200
CANONSBURG, PA 15317-5817

Plant Information

Plant: RELIANT ENERGY MID A/PORTLAND GENERATING STATION
Location: 48 Northampton County 48932 Upper Mt Bethel Township
SIC Code: 4911 Trans. & Utilities - Electric Services

Responsible Official

Name: JAMES V LOCHER
Title: VP COAL PLANT OPERATIONS
Phone: (724) 659 - 8547

Permit Contact Person

Name: TIMOTHY E MCKENZIE
Title: SR ENV SCIENTIST
Phone: (724) 597 - 8670

[Signature] ________________________________
THOMAS A DILAZARO, NORTHEAST REGION AIR PROGRAM MANAGER

SECTION A. Table of Contents

Note: These same sub-sections are repeated for each source!

SECTION A. Table of Contents

SECTION A. Site Inventory List

Source ID	Source Name	Capacity/Throughput		Fuel/Material
031	UNIT NO. 1 W/LOW NOX BURNERS	1,657.200	MMBTU/HR	
			N/A	Bituminous
			N/A	#2 Oil
032	UNIT NO. 2 W/LOW NOX BURNERS	2,511.600	MMBTU/HR	
			N/A	Bituminous
			N/A	#2 Oil
033	AUXILIARY BOILER	12.000	MMBTU/HR	
			N/A	#2 Oil
101	COMBUSTION TURBINE NO. 3		N/A	#2 Oil
			N/A	Natural Gas
102	COMBUSTION TURBINE NO. 4		N/A	#2 Oil
			N/A	Natural Gas
103	COMBUSTION TURBINE NO. 5 W/H2O INJECTION		N/A	#2 Oil
			N/A	Natural Gas
104	MISCELLANEOUS #2 OIL FUELED UNITS (3)			
105	DRAVO HEATER			
106	UNDERGROUND GASOLINE STORAGE TANK			
107	MAIN FUEL OIL STORAGE TANKS (3)			
108	THREE (3) SMALL DIESEL STORAGE TANKS			
P01	FUGITIVE DUSTS - PLANT HAUL ROADS			
P02	FUGITIVE DUSTS - COAL STORAGE & HANDLING			
P03	FUGITIVE DUSTS - ASH DISPOSAL			
C01	UNIT NO. 1 ESP			
C02	UNIT NO. 2 ESP			
CF1	RAILCAR UNLOADING ENCLOSURE			
CF2	BOILER HOUSE FUEL HOPPER ENCLOSURE			
CF3	ASH TRANSFER ENCLOSURES			
CF4	CRUSHER/BREAKER ENCLOSURES			
#25	NATURAL GAS LINE & HEATER			
001	MAIN FUEL OIL STORAGE TANKS (3)			
002	STATION COAL STOCKPILE			
S01	UNIT NO. 1 STACK			
S02	UNIT NO. 2 STACK			
S03	TURBINE NO. 3 STACK			
S04	TURBINE NO. 4 STACK			
S05	TURBINE NO. 5 STACK			
S06	AUXILLIARY BOILER STACK			
Z01	PAVED ROAD DUST EMISSIONS			
Z02	FUGITIVE COAL DUST EMISSIONS			
Z03	ASH DISPOSAL DUST EMISSIONS			
Z04	FUGITVE COMBUSTION LOSSES			
Z05	DRAVO HEATER EMISSIONS			
Z06	GASOLINE TANK FUGITIVES			
Z07	OIL TANK FUGITIVES			
Z08	DIESEL STORAGE FUGITIVES			

PERMIT MAPS

CU 031 → CNTL C01 → STAC S01
FML 001 → CU 031
FML 002 → CU 031

CU 032 → CNTL C02 → STAC S02
FML 001 → CU 032
FML 002 → CU 032

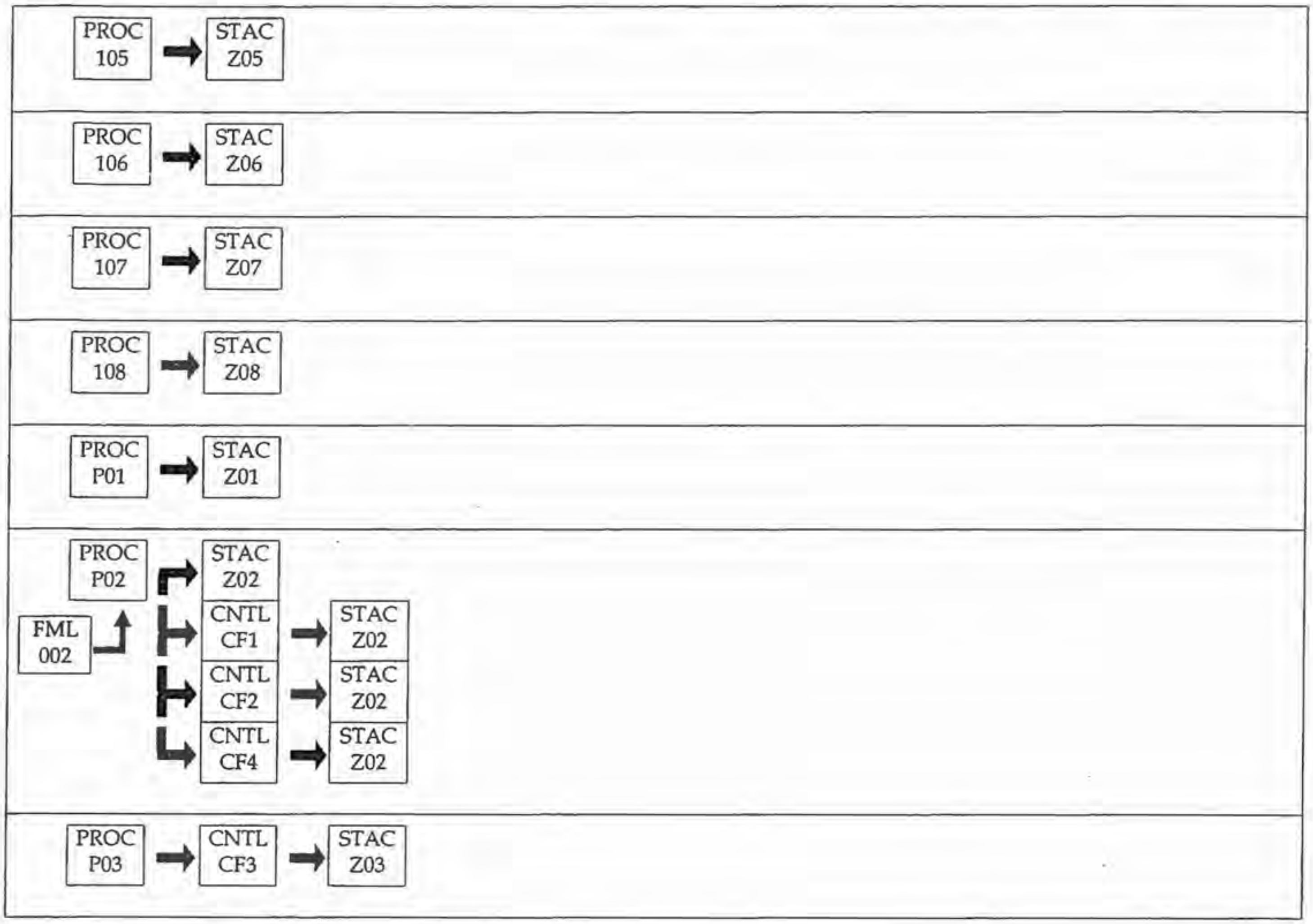
CU 033 → STAC S06
FML 001 → CU 033

PROC 101 → STAC S03
FML 001 → PROC 101
FML #25 → PROC 101

PROC 102 → STAC S04
FML 001 → PROC 102
FML #25 → PROC 102

PROC 103 → STAC S05
FML 001 → PROC 103
FML #25 → PROC 103

PROC 104 → STAC Z04
FML 001 → PROC 104


PROC 105
STAC Z05
PROC 106
STAC Z06
PROC 107
STAC Z07
PROC 108
STAC Z08
PROC P01
STAC Z01
PROC P02
STAC Z02
FML 002
CNTL CF1
STAC Z02
CNTL CF2
STAC Z02
CNTL CF4
STAC Z02
PROC P03
CNTL CF3
STAC Z03

SECTION B. General Title V Requirements

#001 [25 Pa. Code § 121.1]

Definitions

Words and terms that are not otherwise defined in this permit shall have the meanings set forth in Section 3 of the Air Pollution Control Act (35 P.S. § 4003) and 25 Pa. Code § 121.1.

#002 [25 Pa. Code § 127.512(c)(4)]

Property Rights

This permit does not convey property rights of any sort, or any exclusive privileges.

#003 [25 Pa. Code § 127.446(a) and (c)]

Permit Expiration

This operating permit is issued for a fixed term of five (5) years and shall expire on the date specified on Page 1 of this permit. The terms and conditions of the expired permit shall automatically continue pending issuance of a new Title V permit, provided the permittee has submitted a timely and complete application and paid applicable fees required under 25 Pa. Code Chapter 127, Subchapter I and the Department is unable, through no fault of the permittee, to issue or deny a new permit before the expiration of the previous permit. An application is complete if it contains sufficient information to begin processing the application, has the applicable sections completed and has been signed by a responsible official.

#004 [25 Pa. Code §§ 127.412, 127.413, 127.414, 127.446(e) & 127.503]

Permit Renewal

(a) An application for the renewal of the Title V permit shall be submitted to the Department at least six (6) months, and not more than 18 months, before the expiration date of this permit. The renewal application is timely if a complete application is submitted to the Department's Regional Air Manager within the timeframe specified in this permit condition.

(b) The application for permit renewal shall include the current permit number, the appropriate permit renewal fee, a description of any permit revisions and off-permit changes that occurred during the permit term, and any applicable requirements that were promulgated and not incorporated into the permit during the permit term.

(c) The renewal application shall also include submission of proof that the local municipality and county, in which the facility is located, have been notified in accordance with 25 Pa. Code § 127.413. The application for renewal of the Title V permit shall also include submission of compliance review forms which have been used by the permittee to update information submitted in accordance with either 25 Pa. Code § 127.412(b) or § 127.412(j).

(d) The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall submit such supplementary facts or corrected information during the permit renewal process. The permittee shall also provide additional information as necessary to address any requirements that become applicable to the source after the date a complete renewal application was submitted but prior to release of a draft permit.

#005 [25 Pa. Code §§ 127.450(a)(4) & 127.464(a)]

Transfer of Ownership or Operational Control

(a) In accordance with 25 Pa. Code § 127.450(a)(4), a change in ownership or operational control of the source shall be treated as an administrative amendment if:

(1) The Department determines that no other change in the permit is necessary;

(2) A written agreement has been submitted to the Department identifying the specific date of the transfer of permit responsibility, coverage and liability between the current and the new permittee; and,

(3) A compliance review form has been submitted to the Department and the permit transfer has been approved by the Department.

(b) In accordance with 25 Pa. Code § 127.464(a), this permit may not be transferred to another person except in cases of transfer-of-ownership which are documented and approved to the satisfaction of the Department.

SECTION B. General Title V Requirements

#006 [25 Pa. Code § 127.513, 35 P.S. § 4008 and § 114 of the CAA]

Inspection and Entry

(a) Upon presentation of credentials and other documents as may be required by law for inspection and entry purposes, the permittee shall allow the Department of Environmental Protection or authorized representatives of the Department to perform the following:

(1) Enter at reasonable times upon the permittee's premises where a Title V source is located or emissions related activity is conducted, or where records are kept under the conditions of this permit;

(2) Have access to and copy or remove, at reasonable times, records that are kept under the conditions of this permit;

(3) Inspect at reasonable times, facilities, equipment including monitoring and air pollution control equipment, practices, or operations regulated or required under this permit;

(4) Sample or monitor, at reasonable times, substances or parameters, for the purpose of assuring compliance with the permit or applicable requirements as authorized by the Clean Air Act, the Air Pollution Control Act, or the regulations promulgated under the Acts.

(b) Pursuant to 35 P.S. § 4008, no person shall hinder, obstruct, prevent or interfere with the Department or its personnel in the performance of any duty authorized under the Air Pollution Control Act.

(c) Nothing in this permit condition shall limit the ability of the EPA to inspect or enter the premises of the permittee in accordance with Section 114 or other applicable provisions of the Clean Air Act.

#007 [25 Pa. Code §§ 127.25, 127.444, & 127.512(c)(1)]

Compliance Requirements

(a) The permittee shall comply with the conditions of this permit. Noncompliance with this permit constitutes a violation of the Clean Air Act and the Air Pollution Control Act and is grounds for one (1) or more of the following:

(1) Enforcement action

(2) Permit termination, revocation and reissuance or modification

(3) Denial of a permit renewal application

(b) A person may not cause or permit the operation of a source, which is subject to 25 Pa. Code Article III, unless the source(s) and air cleaning devices identified in the application for the plan approval and operating permit and the plan approval issued to the source are operated and maintained in accordance with specifications in the applications and the conditions in the plan approval and operating permit issued by the Department. A person may not cause or permit the operation of an air contamination source subject to 25 Pa. Code Chapter 127 in a manner inconsistent with good operating practices.

(c) For purposes of Sub-condition (b) of this permit condition, the specifications in applications for plan approvals and operating permits are the physical configurations and engineering design details which the Department determines are essential for the permittee's compliance with the applicable requirements in this Title V permit. Nothing in this sub-condition shall be construed to create an independent affirmative duty upon the permittee to obtain a predetermination from the Department for physical configuration or engineering design detail changes made by the permittee.

#008 [25 Pa. Code § 127.512(c)(2)]

Need to Halt or Reduce Activity Not a Defense

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

#009 [25 Pa. Code §§ 127.411(d) & 127.512(c)(5)]

Duty to Provide Information

(a) The permittee shall furnish to the Department, within a reasonable time, information that the Department may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to

SECTION G. Emission Restriction Summary.

Dep Id	Source Description

3.050	Tons/Yr	firing #2 fuel oil	VOC
4.590	Lbs/Hr	firing natural gas	VOC
7.540	Lbs/Hr	firing #2 fuel oil	VOC
8.360	Tons/Yr	firing natural gas*	VOC

104 MISCELLANEOUS #2 OIL FUELED UNITS (3)

Emission Limit		Pollutant
0.040	gr/DRY FT3	P000
500.000	PPMV	SO2

105 DRAVO HEATER

Emission Limit		Pollutant
0.040	gr/DRY FT3	P000
500.000	PPMV	SO2

Site Emission Restriction Summary

Emission Limit	Pollutant

SECTION H. Miscellaneous.

The following sources located at this facility have minor emission and no applicable emission, testing, monitoring, recordkeeping or reporting requirements:

(1) Hydrazine Solution Storage: Hydrazine is stored in drums, and are kept sealed during storage. When in use, the hydrazine is stored in solution in two (2) 400-gallon capacity storage tanks. Any losses from these tanks are due to accidental spillage.
(2) Ammonium Hydroxide Storage: Ammonium Hydroxide is stored in drums, and are kept sealed during storage. When in use, ammonium hydroxide is used to make an ammonia solution, which is stored in two (2) 400-gallon capacity storage tanks. Any losses from these tanks are due to accidental spillage.
(3) Aluminum Sulfate Storage: Aluminum Sulfate is stored in a 400 gallon capacity storage tank. Any losses from this tank are due to accidental spillage.
(4) Main Station, Combustion Turbine, ESP & Coal Transformers: These 17 transformers are sealed units which use non-PCB transformer oils. There are no expected atmospheric emissions.
(5) Dilute Sulfuric Acid Storage: This above-ground tank is a horizontal, fixed roof tank which holds a maximum of 750 gallons of 10% H2SO4 solution. Any losses from this tank are due to accidental spillage.
(6) Concentrated Sulfuric Acid Storage: This above-ground tank is a horizontal, fixed roof tank which holds a maximum of 6,000 gallons of 93% H2SO4 solution. Any losses from this tank are due to accidental spillage.
(7) Dilute Sodium Hydroxide Storage: This above-ground tank is a horizontal, fixed roof tank which holds a maximum of 5,000 gallons of 20% NaOH solution. Any losses from this tank are due to accidental spillage.
(8) Concentrated Sodium Hydroxide Storage: This above-ground tank is a horizontal, fixed roof tank which holds a maximum of 4,000 gallons of 50% NaOH solution. Any losses from this tank are due to accidental spillage.
(9) Water Treatment Dilute Caustic Storage: This above-ground tank is a horizontal, fixed roof tank which holds a maximum of 1,000 gallons of 4% NaOH solution. Any losses from this tank are due to accidental spillage.
(10) Water Treatment Dilute Acid Storage: These two (2) above-ground tanks are horizontal, fixed roof tanks which each hold a maximum of 1,000 gallons of H2SO4 solution. One tank holds a 2% H2SO4 solution, and the other holds a 5% H2SO4 solution. Any losses from these tanks are due to accidental spillage.
(11) Emergency Generator Fuel Storage: Three (3) small storage tanks (275 gallon capacity each) are used to store the diesel fuel used to supply the emergency generators.
(12) Dravo Heater Fuel Oil Storage: This above-ground tank is a horizontal, fixed roof tank which holds a maximum of 1,200 gallons of #2 fuel oil.
(13) Miscellaneous Minor Sources: These include Support Systems equipment (Hydraulic & lubricating oil storage and handling), Battery Charger emissions (emits small amounts of hydrogen gas), Vapor Extractors (to remove condensed water from the lubricating oil reservoir), various Boiler House vents (which release steam, oil vapor, carbon dioxide and small amounts of hydrogen gas), various Vented Equipment (which emit mostly steam and water vapor), and the Water Pretreatment and Wastewater Treatment & Handling (sedimentation basins and the coal run-off pond) systems.

The applicable emission restrictions and operating requirements for the Portland Electric Generating Station are set forth in Sections C through G of this permit. The general Title V requirements of Section B in this permit continue in full force and effect.

EXHIBIT 4

to

PETITION FOR RECONSIDERATION

Summary of Portland Generating Station Modeling Analysis In Support of NJDEP Petition for Reconsideration

Modeling Platform

Modeling of the Portland Generating Plant was performed with the latest EPA approved version of the CALPUFF modeling suite, CALMET/CALPUFF Version 5.8 Level 07063, CALPOST Version 5.6394 Level 070622.

Meteorology*

Meteorological data used included the following:

> 2002 12km MM5 prognostic data obtained from the Ozone Transport Commission (This dataset was used to support the 8-hr Ozone SIPs of the OTC member states)
>
> 10 nearby NWS ASOS hourly surface stations data
>
> 2 NWS upper air stations twice daily observations data
>
> 3 NOAA hourly buoy data

Geophysical Data / Background Data*

Geophysical data used included USGS 30 meter digital elevation model (DEM) data and USGS Land use Land coverage files. 2002 hourly ozone data was obtained from VISTAS.

Computational Grid Size and Receptor Grids

Two separate computational grids were used in the modeling analysis. The first grid used a 500 meter cell size with 75 rows and 75 columns for near field model simulations. A Cartesian grid with 5,625 receptors with 500 meter spacing was used. To locate the maximum impacts 100 meter Cartesian grid consisting of 3600 receptors was used.

The second grid to simulate long range transport consisted of 4 km cells with 100 rows and 100 columns. A discrete receptor grid with 39 receptors was used.

Emission Rates

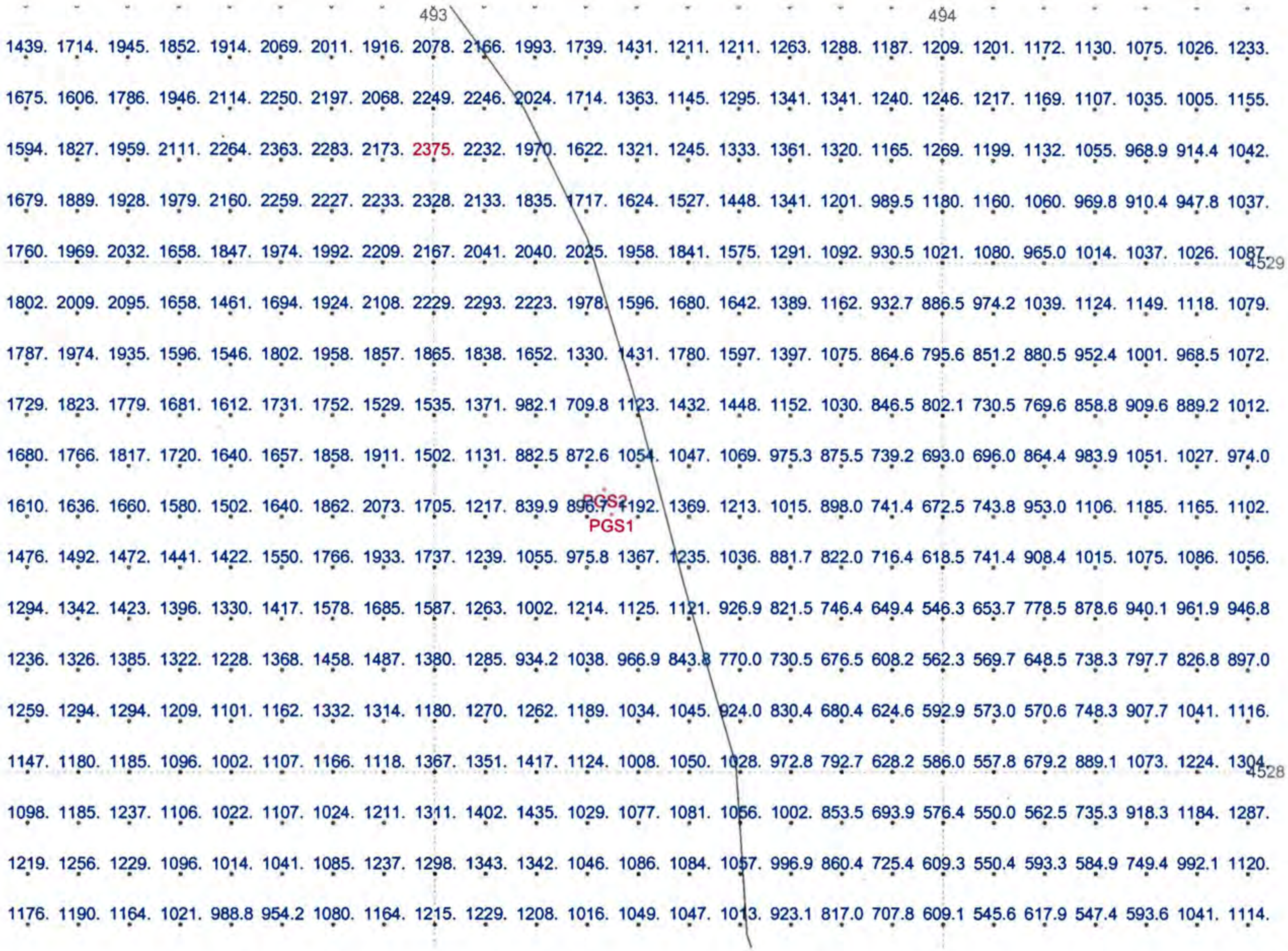
Sulfur Dioxide – Based on allowable 3-hour emission limits;
Unit 1 = 5820 lb/hr
Unit 2 = 8900 lb/hr

Nitrogen Oxides – Unit 1 based on lbs/MMBtu concentration limit and heat input of 1657.2 MMBtu/hr, Unit 2 based on 30-day limit of 379.4 tons/month;
Unit 1 = 613.2 lb/hr
Unit 2 = 1053.9 lb/hr

PM-2.5 – Based on allowable TSP concentration limit of 0.1 MMBtu/hr, AP-42 emission factors (Tables 1.1-5 and 1.1.6), June 13, 2006 stack test on Unit 1, and heat inputs of 1657.2 MMBtu/hr for Unit 1 and 2511.6 MMBtu/hr for Unit 2.
Unit 1 = 358.8 lb/hr
Unit 2 = 543.8 lb/hr

Scale: 1" = 0.3 Km

Figure 1 Portland Generating Plant Maximum H2H 24-hr PM-2.5 Impacts



Scale: 1" = 0.3 Km

Figure 2 Portland Generating Plant Maximum H2H 3-hr SO2 Impacts

								493										494							
204.1	225.3	249.8	272.7	300.6	328.0	350.7	367.1	372.4	313.3	329.4	311.8	288.7	333.6	338.2	374.9	395.9	364.3	327.3	281.4	262.8	295.0	319.9	336.9	316.3	
218.1	241.7	267.8	290.9	317.2	340.5	359.3	372.7	374.7	333.9	339.0	299.5	295.9	342.5	371.7	405.3	406.3	361.3	310.5	257.1	281.9	312.3	335.1	312.9	290.3	
236.1	258.5	285.8	306.6	329.5	348.8	363.5	371.5	367.5	348.8	322.4	279.1	298.2	351.8	401.5	426.3	396.0	338.3	280.2	246.8	288.9	316.4	299.7	279.2	266.9	
259.8	274.2	300.0	316.8	335.8	351.1	359.4	360.1	349.9	329.9	295.9	273.8	304.7	373.3	416.6	414.9	356.7	287.6	229.9	238.2	279.2	279.3	258.5	243.7	275.2	
281.3	298.0	312.9	321.0	335.8	347.5	351.7	355.5	350.8	340.4	329.0	318.1	302.7	388.8	415.4	375.0	291.5	220.3	173.6	215.0	250.8	234.1	214.6	228.1	265.4	4529
299.5	320.9	341.1	348.0	363.9	379.5	391.7	369.9	328.9	315.7	301.6	277.2	318.8	376.7	372.8	284.7	201.4	152.3	156.0	182.2	207.0	190.7	198.3	208.0	216.1	
308.8	332.4	356.5	368.8	369.3	352.3	349.1	331.2	290.6	258.2	224.6	260.2	307.7	374.2	307.4	218.3	174.9	144.7	136.5	151.2	163.1	174.1	179.9	176.6	181.8	
313.5	339.1	345.1	318.2	328.0	329.7	314.9	282.1	224.6	176.2	137.9	209.6	249.0	331.2	234.7	188.5	159.8	130.4	127.5	147.3	133.2	145.4	153.5	160.2	174.5	
302.8	317.8	325.3	304.6	294.7	285.1	257.7	239.2	188.2	141.6	136.1	113.8	230.2	205.6	182.7	154.9	148.5	126.2	122.1	120.5	145.0	162.1	171.5	175.1	170.5	
306.2	320.2	324.4	297.1	275.2	242.4	273.0	268.9	213.6	154.9	129.1	137.0 PGS2 PGS1	163.8	233.8	203.4	144.8	129.4	116.2	110.4	127.4	149.2	162.0	168.8	175.3	181.0	
306.9	316.3	319.6	290.7	265.6	233.6	274.8	273.9	217.8	173.4	151.6	133.7	239.2	220.7	183.1	141.8	122.8	110.2	98.81	113.6	130.6	143.4	151.1	160.4	187.3	
297.5	310.0	308.5	277.9	251.1	211.6	247.6	248.0	201.3	181.2	150.2	167.9	176.8	217.3	165.3	127.7	108.5	98.47	94.42	97.74	112.5	124.7	132.5	156.8	191.3	
283.6	296.9	293.2	261.1	232.4	193.2	207.8	208.6	202.9	182.5	151.7	153.6	179.7	176.7	153.5	139.5	121.2	98.46	89.51	95.14	94.50	105.5	117.1	151.3	187.1	
270.1	280.0	273.8	241.1	211.9	176.5	186.0	203.4	199.0	205.0	202.4	174.1	161.1	153.1	143.3	126.9	106.9	93.02	86.21	106.7	98.23	109.8	124.1	145.9	170.6	
254.7	260.3	252.4	218.7	190.7	182.5	183.8	204.2	216.2	229.5	217.3	207.0	184.3	166.5	149.6	127.2	104.0	85.82	83.78	93.06	108.4	129.2	145.4	168.0	185.1	4528
243.6	244.1	236.6	204.2	190.2	190.3	205.2	225.8	216.4	231.8	236.2	228.0	208.6	177.5	150.6	131.9	111.1	91.70	80.96	77.61	97.10	120.0	145.0	210.2	232.2	
223.3	222.9	214.4	186.9	180.3	194.2	211.7	217.6	215.9	229.5	233.8	227.8	212.2	186.6	157.9	128.2	111.5	95.13	81.24	76.76	95.31	118.7	153.6	220.6	236.6	
213.6	218.3	215.9	183.9	181.4	195.2	209.5	208.9	205.4	216.7	220.7	216.3	204.2	184.1	160.3	134.3	108.2	92.54	80.66	75.33	90.95	115.4	153.4	232.3	258.7	

Scale: 1" = 0.3 Km

Figure 3 Portland Generating Plant Maximum H2H 24-hr SO2 Impacts

E:
Long Range Transport
Calmet Files
C:9/11/2007 09:48 43,442 calmet.inp E:\Long Range Transport\Calmet Files\
C:9/11/2007 17:55 1,077,640 calmet.lst E:\Long Range Transport\Calmet Files\
C:9/11/2007 17:15 134,533 QA3D.DAT E:\Long Range Transport\Calmet Files\
C:9/11/2007 09:48 135 qabuoysta.dat E:\Long Range Transport\Calmet Files\
C:8/23/2007 14:57 290 qassta.dat E:\Long Range Transport\Calmet Files\
C:8/23/2007 14:57 107 qausta.dat E:\Long Range Transport\Calmet Files\
Calmet Files
Calpost Files
C:9/13/2007 11:58 24,272 CALPOST.INP E:\Long Range Transport\Calpost Files\
C:9/13/2007 11:42 70,632 calpost.lst E:\Long Range Transport\Calpost Files\
C:9/13/2007 11:52 87,765 portland_lrtlt_totpm_calpost.lst E:\Long Range Transport\Calpost Files\
C:9/13/2007 11:52 1,669 rank(0)_totpm_8719hr_conc_lrt.dat E:\Long Range Transport\Calpost Files\
C:9/13/2007 11:52 2,243 rank(all)_totpm_24hr_conc_lrt.dat E:\Long Range Transport\Calpost Files\
Calpost Files
Calpuff Files
C:9/12/2007 10:51 80,133 CALPUFF.INP E:\Long Range Transport\Calpuff Files\
C:9/12/2007 10:14 259,505 CALPUFF.LST E:\Long Range Transport\Calpuff Files\
C:9/12/2007 10:26 80,113 CALPUFF_LRT.INP.txt E:\Long Range Transport\Calpuff Files\
C:9/12/2007 10:41 262,765 PORTLAND_LRT_CALPUFF.LST E:\Long Range Transport\Calpuff Files\
C:9/12/2007 10:41 4,169,820 PORTLAND_LRT_CONC.DAT E:\Long Range Transport\Calpuff Files\
C:9/12/2007 11:05 262,885 PORTLAND_LRT_SO4_CALPUFF.LST E:\Long Range Transport\Calpuff Files\
C:9/12/2007 11:05 5,687,664 PORTLAND_LRT_SO4_CONC.DAT E:\Long Range Transport\Calpuff Files\
C:9/12/2007 10:51 50,110 qaluse.grd E:\Long Range Transport\Calpuff Files\
C:9/12/2007 10:51 19,515 qao3sta.dat E:\Long Range Transport\Calpuff Files\
C:9/12/2007 10:51 103 qapnts.dat E:\Long Range Transport\Calpuff Files\
C:9/12/2007 10:51 1,977 qarecd.dat E:\Long Range Transport\Calpuff Files\
C:9/12/2007 10:51 120,210 qaterr.grd E:\Long Range Transport\Calpuff Files\
Calpuff Files
Geo
C:9/7/2007 13:54 12,694 ctgproc.inp E:\Long Range Transport\Geo\
C:9/7/2007 13:57 128,921 ctgproc.lst E:\Long Range Transport\Geo\
C:9/7/2007 13:57 2,600,410 landuse.dat E:\Long Range Transport\Geo\
C:9/7/2007 13:59 643,693 MAKEGEO.DAT E:\Long Range Transport\Geo\
C:9/7/2007 13:59 15,059 MAKEGEO.INP E:\Long Range Transport\Geo\
C:9/7/2007 13:59 439,511 MAKEGEO.LST E:\Long Range Transport\Geo\
C:9/7/2007 13:59 50,110 QALUSE.GRD E:\Long Range Transport\Geo\
C:9/7/2007 13:59 120,210 QATERR.GRD E:\Long Range Transport\Geo\
C:9/7/2007 13:59 82,408 terrel.dat E:\Long Range Transport\Geo\
C:9/7/2007 13:59 82,092 terrel.grd E:\Long Range Transport\Geo\
C:9/7/2007 13:58 21,078 TERREL.INP E:\Long Range Transport\Geo\
C:9/7/2007 13:59 239,592 terrel.lst E:\Long Range Transport\Geo\
Geo
Long Range Transport
NearField Domain
Calmet Files
C:8/22/2007 13:30 43,442 calmet.inp E:\NearField Domain\Calmet Files\
C:8/22/2007 19:40 687,551 calmet.lst E:\NearField Domain\Calmet Files\
C:8/22/2007 19:08 134,533 QA3D.DAT E:\NearField Domain\Calmet Files\
C:8/23/2007 14:57 67,610 qalai.grd E:\NearField Domain\Calmet Files\
C:8/23/2007 14:57 28,235 qaluse.grd E:\NearField Domain\Calmet Files\
C:8/23/2007 14:57 67,685 qaterr.grd E:\NearField Domain\Calmet Files\
C:8/23/2007 14:57 67,610 qaz0.grd E:\NearField Domain\Calmet Files\
Calmet Files
Calpost Files
C:9/13/2007 14:31 24,288 CALPOST.INP E:\NearField Domain\Calpost Files\
C:8/24/2007 10:16 2,009,813 calpost_500m_so2.lst E:\NearField Domain\Calpost Files\
C:8/24/2007 10:33 887,963 calpost_500m_totpm.lst E:\NearField Domain\Calpost Files\
C:9/7/2007 10:07 915,540 calpost_so2_100m.lst E:\NearField Domain\Calpost Files\
C:9/13/2007 14:31 805,924 calpost_totpm_100m.lst E:\NearField Domain\Calpost Files\
C:8/24/2007 10:16 219,591 exceed_so2_24hr_500m_conc.dat E:\NearField Domain\Calpost Files\
C:8/24/2007 10:16 219,591 exceed_so2_3hr_500m_conc.dat E:\NearField Domain\Calpost Files\
C:8/24/2007 10:16 219,523 rank(0)_so2_8719hr_500m_conc.dat E:\NearField Domain\Calpost Files\
C:9/7/2007 10:07 140,548 rank(0)_so2_8719hr_conc_100m.dat E:\NearField Domain\Calpost Files\
C:8/24/2007 10:33 219,523 rank(0)_totpm_8719hr_500m_conc.dat E:\NearField Domain\Calpost Files\
C:9/13/2007 14:31 140,548 rank(0)_totpm_8719hr_conc_100m.dat E:\NearField Domain\Calpost Files\
C:8/24/2007 10:16 298,301 rank(all)_so2_24hr_500_conc.dat E:\NearField Domain\Calpost Files\
C:9/7/2007 10:07 190,976 rank(all)_so2_24hr_conc_100m.dat E:\NearField Domain\Calpost Files\
C:9/6/2007 09:17 7,861 rank(all)_so2_24hr_conc_kitt.dat E:\NearField Domain\Calpost Files\
C:8/24/2007 10:16 298,301 rank(all)_so2_3hr_500m_conc.dat E:\NearField Domain\Calpost Files\
C:9/7/2007 10:07 190,976 rank(all)_so2_3hr_conc_100m.dat E:\NearField Domain\Calpost Files\
C:8/24/2007 10:33 298,301 rank(all)_totpm_24hr_500m_conc.dat E:\NearField Domain\Calpost Files\
C:9/13/2007 14:31 291,806 rank(all)_totpm_24hr_conc_100m.dat E:\NearField Domain\Calpost Files\

Calpost Files

Calpuff Files

C:9/6/2007 15:46	318,889	CALPUFF.INP E:\NearField Domain\Calpuff Files\
C:9/6/2007 14:38	912,278	CALPUFF.LST E:\NearField Domain\Calpuff Files\
C:9/12/2007 09:58	318,889	Portland_100m_grid_CALPUFF.INP.txt E:\NearField Domain\Calpuff Files\
C:9/7/2007 03:14	913,874	PORTLAND_100M_GRID_CALPUFF.LST E:\NearField Domain\Calpuff Files\
C:9/7/2007 03:14	78,436,776	PORTLAND_100M_GRID_CONC.DAT E:\NearField Domain\Calpuff Files\
C:9/5/2007 09:23	451,491	Portland_500m_grid_CALPUFF.INP.txt E:\NearField Domain\Calpuff Files\
C:8/24/2007 07:53	1,284,914	PORTLAND_500M_GRID_CALPUFF.LST E:\NearField Domain\Calpuff Files\
C:8/24/2007 07:53	93,080,876	PORTLAND_500M_GRID_CONC.DAT E:\NearField Domain\Calpuff Files\
C:9/6/2007 16:50	28,235	qaluse.grd E:\NearField Domain\Calpuff Files\
C:9/6/2007 16:50	19,515	qao3sta.dat E:\NearField Domain\Calpuff Files\
C:9/6/2007 16:50	103	qapnts.dat E:\NearField Domain\Calpuff Files\
C:9/6/2007 16:50	180,027	qarecd.dat E:\NearField Domain\Calpuff Files\
C:9/6/2007 16:50	67,685	qaterr.grd E:\NearField Domain\Calpuff Files\

Calpuff Files

GEO

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C:8/21/2007 11:19	54,818	ctgproc.lst E:\NearField Domain\GEO\
C:8/21/2007 11:19	1,462,910	landuse.dat E:\NearField Domain\GEO\
C:8/21/2007 11:20	362,743	MAKEGEO.DAT E:\NearField Domain\GEO\
C:8/21/2007 11:20	15,054	MAKEGEO.INP E:\NearField Domain\GEO\
C:8/21/2007 11:20	252,388	MAKEGEO.LST E:\NearField Domain\GEO\
C:8/21/2007 11:20	28,235	QALUSE.GRD E:\NearField Domain\GEO\
C:8/21/2007 11:20	67,685	QATERR.GRD E:\NearField Domain\GEO\
C:8/21/2007 11:20	46,608	terrel.dat E:\NearField Domain\GEO\
C:8/21/2007 11:20	46,286	terrel.grd E:\NearField Domain\GEO\
C:8/21/2007 11:20	20,079	TERREL.INP E:\NearField Domain\GEO\
C:8/21/2007 11:20	129,432	terrel.lst E:\NearField Domain\GEO\

GEO

Met

C:8/22/2007 10:04	682,494	14735_02.ua E:\NearField Domain\Met\
C:8/22/2007 10:05	702,923	93734_02.ua E:\NearField Domain\Met\
C:8/22/2007 10:06	721,921	93755_02.ua E:\NearField Domain\Met\
C:8/16/2007 16:06	5,799	READ62.INP E:\NearField Domain\Met\
C:2/20/2007 19:06	1,209,336	sea1.DAT E:\NearField Domain\Met\
C:2/20/2007 19:06	1,209,336	sea2.DAT E:\NearField Domain\Met\
C:2/20/2007 19:06	1,209,336	sea3.DAT E:\NearField Domain\Met\
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C:8/16/2007 10:22	10,617	smerge04725.lst E:\NearField Domain\Met\
C:8/16/2007 10:22	5,145	smerge13739.lst E:\NearField Domain\Met\
C:8/16/2007 10:22	3,586	smerge13781.lst E:\NearField Domain\Met\
C:8/16/2007 10:22	3,347	smerge14734.lst E:\NearField Domain\Met\
C:8/16/2007 10:22	3,247	smerge14737.lst E:\NearField Domain\Met\
C:8/16/2007 10:23	3,288	smerge14777.lst E:\NearField Domain\Met\
C:8/16/2007 10:23	3,330	smerge14778.lst E:\NearField Domain\Met\
C:8/16/2007 10:23	3,372	smerge93721.lst E:\NearField Domain\Met\
C:8/16/2007 10:23	3,413	smerge93730.lst E:\NearField Domain\Met\
C:8/16/2007 10:23	3,454	smerge93738.lst E:\NearField Domain\Met\
C:8/16/2007 10:23	5,200,212	surf.dat E:\NearField Domain\Met\

Met

NearField Domain

E: