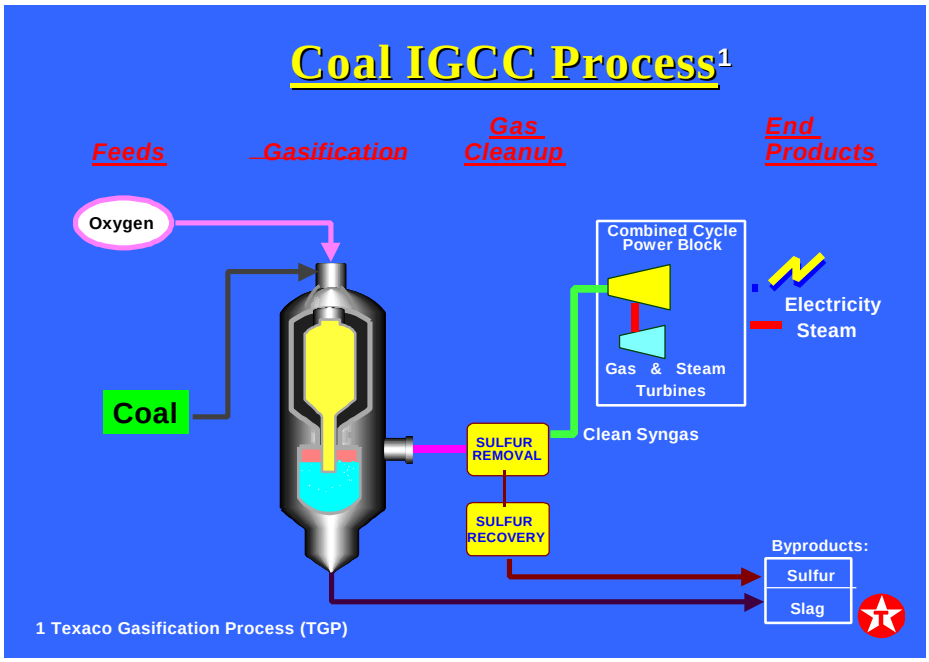
Increasing Electricity Availability From Coal-Fired Generation in the Near-Term
May 2001



THE NATIONAL COAL COUNCIL

Increasing Electricity Availability From Coal-Fired Generation in the Near-Term

Chair: Mr. Steven F. Leer

Vice Chair: Mr. Wes M. Taylor

Study Work Group Chair: Ms. Georgia Nelson

The National Coal Council
May 2001

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Steven F. Leer, Chairman

Robert A. Beck, Executive Director

U.S. DEPARTMENT OF ENERGY

Spencer Abraham, Secretary of Energy

The National Coal Council is a Federal Advisory Committee to the Secretary of Energy. The sole purpose of the National Coal Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to coal or to the coal industry.

Cover Letter to Secretary Abraham

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May 3, 2001

The Honorable Spencer Abraham
Secretary of Energy
United States Department of Energy
Room 7A-219
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Dear Mr. Secretary:

On behalf of The National Coal Council I am pleased to submit the enclosed report entitled "Increasing Electricity Availability from Coal-Fired Generation in the Near-Term." This report was authorized by your predecessor then-Secretary Bill Richardson, on November 13, 2000 prepared, deliberated and recommended by the Coal Policy Committee at its meeting on April 3, 2001, and formally approved by The National Coal Council on May 3, 2001.

In his letter, Secretary Richardson requested that The National Coal Council conduct a study on measures, which the government or government in partnership with industry, could undertake to improve the availability of electricity from coal-fired power plants. His letter requested that the Council address improving coal-fired generation availability in two specific areas:

- Improving technologies at coal-fired electric generating plants to produce more electricity, and
- Reducing regulatory barriers to using these technologies.

The Council accepted Secretary Richardson's request and formed a study group of experts to conduct the work. The study group conducted its work at the direction of the Coal Policy Committee of the Council, which is chaired by Malcolm Thomas, Vice President of Kennecott Energy and a member of the Council. The study group itself was chaired by Georgia Nelson, President of Midwest Generation Company and a member of the Council.

The study was divided into two major sections: technologies and regulatory reform. The focus of the technologies section is on achieving more electricity from existing and new coal-fired power plants using technologies that improve efficiency, availability and environmental performance in the near term defined as the next 36 months.

However, unless there is a significant change in regulatory interpretation and enforcement regarding the installation of new technologies at existing power plants, it is not likely that any of this additional low-cost, low-cost emission electricity will be produced. The recent change in enforcement procedures by EPA, reinterpreting as violations of the Clean Air Act what had heretofore been considered routine maintenance at power plants, has had a direct and chilling effect on all maintenance and efficiency improvements, and clean coal technology installations at existing power plants. A return to the pre-1998

interpretation of this one regulation would allow plant operators the opportunity to install technologies discussed in the report.

Several other existing regulations seem to be in conflict with the country's attempt to maximize the use of domestic energy sources, as well. Environmental regulation should be harmonized with the energy and national security goals of the country.

The National Coal Council strongly recommends that the country, with the Department of Energy in the lead, develop a clear comprehensive energy policy that supports the maximum use of domestic fuel sources, continues to protect the environment by implementing strong but balanced environmental regulations, and harmonizes conflicting regulations affecting energy development and use. Government and the private sector should work in partnership to achieve the desired goals and remove those regulatory barriers that create obstacles to achieving those goals, while preserving environmental performance. The specific recommendations of the Council can be found in the Executive Summary of the report.

The Council appreciates being asked to provide this report and we stand ready to answer any questions you may have about it.

Sincerely,

Steven F. Leer

Steven F. Leer
Chairman

Enclosure

Abbreviations

AQRVs	Air quality related values
B&W	Babcock & Wilcox
BACT	Best available control technology
BGL	British Gas/Lurgi
Btu	British thermal units
Btu/kWh	British thermal units per kilowatt-hour
CAA	Clean Air Act
CFB	Circulating fluidized bed
CO_2	Carbon dioxide
COS	Carbonyl sulfide
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FGD	Flue gas desulfurization
FLMS	Federal land managers
GADS	Generation Availability Data System
GW	Gigawatts (10^9 watts)
HHV	Higher heating value
HRSG	Heat recovery steam generator
IGCC	Integrated gasification combined cycle
kW	Kilowatt
lb/MBtu	Pounds of emissions per million Btu of heat input
LAER	Lowest achievable emission rates
LHV	Lower heating value
LNB	Low NO_x burners
MACT	Maximum achievable control technology
Mbtu	Million Btu
MDGC	Maximum demonstrated generating capacity
MW	Megawatts (10^6 watts)
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NCC	National Coal Council
NERC	North American Electric Reliability Council
NGCC	Natural gas combined cycle
NOVs	Notices of violation
NO_x	Nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	Operating and Maintenance
OEM	Original Equipment Manufacturer
PPM	Parts Per Million
PSD	Prevention of significant deterioration
SCR	Selective catalytic reduction
SO_2	Sulfur dioxide
SO_x	Sulfur oxides
tpy	tons per year
UDI	Utility Data Institute
WEPCo	Wisconsin Electric Power Company

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Preface

The National Coal Council is a private, nonprofit advisory body, chartered under the Federal Advisory Committee Act.

The mission of the Council is purely advisory: to provide guidance and recommendations as requested by the United States Secretary of Energy on general policy matters relating to coal. The Council is forbidden by law from engaging in lobbying or other such activities. The National Coal Council receives no funds or financial assistance from the Federal government. It relies solely on the voluntary contributions of members to support its activities.

Members of the National Coal Council are appointed by the Secretary of Energy for their knowledge, expertise, and stature in their respective fields of endeavor. They reflect a wide geographic area of the United States (representing more than 30 states) and a broad spectrum of diverse interests from business, industry, and other groups, such as:

?? large and small coal producers;
?? coal users such as electric utilities and industrial users;
?? rail, waterways, and trucking industries as well as port authorities;
?? academia;
?? research organizations;
?? industrial equipment manufacturers;
?? state government, including governors, lieutenant governors, legislators, and public utility commissioners;
?? consumer groups, including special women's organizations;
?? consultants from scientific, technical, general business, and financial specialty areas;
?? attorneys;
?? state and regional special interest groups; and
?? Native American tribes.

The National Coal Council provides advice to the Secretary of Energy in the form of reports on subjects requested by the Secretary and at no cost to the Federal Government.

Executive Summary

Purpose

By letter dated November 13, 2000, then-Secretary of Energy Bill Richardson requested that the National Coal Council conduct a study on measures which the government or the government in partnership with industry could undertake to improve the availability of electricity from coal-fired power plants. His letter requested that the Council address improving coal-fired generation availability in two specific areas:

?? improving technologies at coal-fired electric generating plants to produce more electricity; and
?? reducing regulatory barriers to using these technologies.

The Council accepted the Secretary's request and formed a study group of experts to conduct the work and draft a report. The list of participants of this study group can be found in Appendix D of the report.

Findings

The study group found the following.

?? Nationally, approximately 40,000 megawatts of increased electrical production capability is possible now from existing coal-fired power plants.
?? Such increased electricity supply can be available through the installation of standard improvements and clean coal technologies. This will have the important effect of increasing efficiency and decreasing emissions per megawatt from such modified plants, thereby improving air quality.
?? Such plant efficiency and increased electricity production capability may only be realized if a return to historic regulatory policy is made.
?? Coal-based electricity will be important for many years into the future. Therefore, regulations and policies employed should encourage the clean use of this resource through accelerated installation of more efficient, cleaner technologies.

The study was divided into two major sections: technology and regulatory reform. The focus of the technology section is on achieving more electricity from existing and new coal-fired power plants using technologies that improve efficiency, availability, and environmental performance. The discussion is divided into three subsections:

a) achieving higher availability/reliability in the existing fleet of coal-fired plants;
b) Increasing generation output of existing coal-fired plants; and
c) Determining opportunities for repowering existing facilities with clean coal technologies as well as building new advanced clean coal technology generation facilities.

Analysis of the U.S. utility industry infrastructure of coal plants reveals a significant potential for increasing generation capacity by taking well-tested measures to improve the reliability/availability of older facilities. This effort, which will come mainly from improvements on the steam generators of these older plants, can create 10,000 MW of new capacity.

Techniques to recover lost capacity and increase capacity above nameplate have been collected from a combination of research studies by utility industry organizations such as EPRI and actual case studies

which are detailed in the report. The nameplate capacity of coal units older than 20 years is approximately 220,000 MW; however, due to derating, the existing capacity is only about 200,000 MW. This group of plants has the potential for both capacity restoration (about 20,000 MW) and/or improvement (about 20,000 MW). It is estimated that this increased capacity of 40,000 MW could be recovered within 36 months. This can allow the economy to grow while new generation facilities are sited, constructed, and brought into service.

For new coal-fired power generating capacity, Pulverized Coal Combustion in supercritical steam plants (a mature technology) is available with minimal emissions, high efficiency, and at very favorable total production cost.

Repowering of an old existing coal fired power plant with a single modern steam generating unit, equipped with commercially proven emissions controls results in significant reductions in the total amounts of emissions even while substantially increasing the total MWh output of the facility.

Integrated Gasification Combined Cycle (IGCC) has become a commercially available technology for both greenfield and repowering applications. IGCC is a clean, new technology option insensitive to fuel quality variation.

While natural gas will fuel the majority of new capacity additions during this time period there are currently about 321,000 MW of coal-fired capacity in service. While not all of this capacity can be targeted for the new technologies discussed in this report, it is estimated that 75% of it can be retrofitted with one of these technologies. This additional increase in capacity is estimated to be 40,000 MW and much of it could be brought on line in the next three years. This minimizes economic impacts while new generation facilities are sited, constructed, and brought into service without increasing emissions at existing facilities and, in some cases, lowering emissions. Approximately 25% of existing facilities can be targeted for repowering with much cleaner and more efficient coal-based power generation.

However, unless there is a significant change in regulatory interpretation and enforcement regarding the installation of new technologies at existing power plants, it is not likely that any of this additional low-cost, low emission electricity will be produced. The recent change in enforcement procedures by EPA (reinterpreting as violations of the Clean Air Act what had heretofore been considered routine maintenance at power plants) has had a direct and chilling effect on all maintenance and efficiency improvements and clean coal technology installations at existing power plants. EPA has brought legal action against 11 companies and 49 generation facilities since 1998 under the New Source Review section of the 1990 Clean Air Act. The companies involved believe that they were conducting routine maintenance needed to keep these plants in good condition. The result has been that no new efficiency, availability, or environmental improvement has occurred since 1998 when EPA changed its enforcement policy. A return to the historic interpretation of this one regulation alone would allow plant operators the opportunity to install technologies discussed in the report. If just a three percent increase in capacity could be achieved through reducing outages and increasing plant efficiency, it could result in over 11,500 MW of coal-based capacity being added to the current fleet while continuing the downward trend in emissions.

Several other existing regulations seem to be in conflict with the country's attempt to maximize the use of domestic energy sources. Environmental regulation should be harmonized with the energy and national security goals of the country.

Recommendations

The National Coal Council strongly recommends that the country, with the Department of Energy in the lead, develop a clear, comprehensive energy policy that supports the maximum use of domestic fuel sources, continues to protect the environment by implementing strong but balanced environmental regulations, and harmonizes conflicting regulations affecting energy development and use. Government and industry should work in partnership to achieve the desired goals and remove those regulatory barriers that create obstacles to achieving those goals while preserving environmental performance.

Specifically, the Council recommends that the Department of Energy take the following actions.

- ?? Initiate and lead a dialogue with EPA, with the goal of returning to the traditional pre-1998 interpretation of the New Source Review section of the 1990 Clean Air Act.
- ?? Promote accelerated installation of clean and efficient technologies at new and existing coal-fired power plants.
- ?? Initiate and lead a dialogue with EPA to promote coordinated regulations for ozone attainment into a single compliance strategy.
- ?? Initiate and lead a dialogue with EPA and electricity generators to establish credible and uniform emissions targets, which will provide regulatory certainty for a sufficient period in the future to assure electricity generators that they can achieve a return on investments for performance and environmental improvements.
- ?? Lead the country's effort to develop a clear, comprehensive, and secure energy policy that maximizes the use of domestic fuels, including coal, while continuing the downward trend in emissions.

Achieving Higher Availability/Reliability From Existing Coal-Fired Power Plants

This section will focus on recommendations that will improve existing coal-fired power plants' reliability and availability to eliminate or reduce forced outages and extend the time between planned maintenance outages. This suggested availability improvement program is meant to restore the plants' infrastructure to a level that restores the original reliability of the plants. Implementation of these recommendations will allow the plants to increase generation output above recent historical output without increasing gross generating capability.

We will show from the use of industry sources on reliability (GADS/NERC) and generation capacity (EIA) that there is a significant opportunity for the utility industry to increase the generation output from our existing fleet of coal-fired power plants by restoring portions of the plant infrastructure to their original condition.

Analysis of the U.S. utility industry's coal-fired plant infrastructure reveals a significant opportunity for increasing electricity output from these plants by taking measures to improve the reliability/availability of the older facilities. Maintaining or restoring plants that are over 20 years old to a condition similar to plants that are under 20 years old can result in more reliable facilities that will be available to play an important role in supporting the increasing strain on our electrical system's reserve margins and electrical demand growth.

Specifically, our analysis has shown that this reliability improvement effort can create 10,000 MWs of equivalent generation capacity within our existing coal-fired fleet of plants. Of particular note is that over 90% of these MWs of capacity will come from component replacement and material upgrades of the boiler/steam generator at our facilities that are more than 20 years old. The U.S. EPA has focused on boiler/steam generator component replacement projects in its recent enforcement actions, applying New Source Review ("NSR") standards to repairs formerly considered routine maintenance, repair, or replacement. The potential regulatory consequences of the EPA's enforcement actions may prevent the utility industry from taking full advantage of this relatively inexpensive way to increase the availability of our national electric generating capacity, which could be implemented in a two to three year time frame.

The U.S. electric generating system's reserve margins have declined dramatically over the last 20 years. This situation has put pressure on the operators of our existing coal-fired fleet to restore, maintain, or improve the reliability and availability of their facilities to keep pace with the growing demand for electricity in the face of limited new capacity coming on line. The mandate for higher availability, lower forced outage rates, and longer time spans between planned outages is more critical today than ever in our history.

The causes of plant unavailability are well defined, and sound, technology-based solutions are commercially available to improve plant availability and help restore our historic reserve margins.

Causes of plant unavailability and recommendations for solutions have been generally categorized according to the magnitude of their impact on plant availability in the following list:

Area 1: Boiler/Steam Generator

The primary cause of unavailability of our coal-fired plants is the reliability of the boiler/steam generator. Severe duty on both the fire side and the water/steam side of the various heat transfer surfaces in the boiler/steam generator cause frequent unplanned outages and lengthening of planned outages to repair

failures to these critical components of the power plant. Replacement of these components will significantly reduce outages and increase the facility's availability and total generation output capability. Examples of our recommendations for improving the availability of the boiler/steam generator are:

a. furnace wall panel replacements;
b. reheater component replacements;
c. primary superheater component replacements;
d. secondary superheater component replacements;
e. economizer replacements;
f. various header replacements;
g. furnace floor replacements;
h. cyclone burner replacements; and
i. incorporation of improved materials of construction for items a-h.

This area represents between 50% and 70% (depending on age, design, and operating history of the unit) of all lost generation from our coal-fired fleet. The industry data sources referenced above indicate that if improvements to the boilers/steam generators on our plants that are older than 20 years can be made to restore these facilities to the condition of plants that are under 20 years, we will benefit from an attendant improvement in reliability/availability. To help quantify this finding, plants older than 20 years are, on average, currently experiencing nearly 10% loss of achievable generation due to problems in the boiler/steam generator. This compares to approximately 5% loss for plants that are less than 20 years old. If we can recover only this differential through restoration of the boiler/steam generator, we will be taking advantage of nearly 9,000 MWs of available generation capacity in our existing coal-fired generating fleet. This figure is expected to increase significantly as our older generating units are dispatched more often to meet the growing demand for electricity considering the less than adequate new capacity coming on line.

Although the implementation of any (or all) of these recommendations will significantly increase plant availability, recent regulatory treatment of previously routine repairs, maintenance, and replacement as modifications by the EPA discourages utilities from pursuing these kinds of projects in their future plans for availability improvement for fear of triggering NSR with accompanying permitting and modeling requirements. NSR can radically undermine the economic feasibility of these projects, preventing recapture of lost generating capacity or increased reliability.

Area 2: Steam Turbine/Generator

Problems with the steam turbine/generator represent the second largest source of reduced generation capability in coal-fired plants. This area represents a 3% loss of generation compared to up to 10% for the boiler/steam generator. An interesting finding from our analysis is that the data sources referenced above show very little difference in loss of generation capability due to turbine/generator problems between plants older than 20 years and plants younger than 20 years. This phenomenon may be due to the regimented safety and preventative maintenance program typically mandated by turbine manufacturers and followed by plant owners for the steam turbine/generator.

Section 2 describes turbine/generator improvements (e.g., uprating) that can change gross plant outputs without changing the turbine/generator's relatively good track record on availability. In addition to turbine uprating, some of the general improvements that have occurred in steam turbine design will also improve the availability/reliability of existing steam turbines. Recommendations include:

a. turbine blading replacements with improved shapes (CFD modeling) and materials of construction to increase turbine efficiency and reliability;
b. implementation of measures to reduce or eliminate droplet formation and the resultant blade erosion preserving turbine reliability and performance; and
c. turbine/generator inclusion in plant diagnostic and data acquisition system for predictive maintenance (reference area 7c below) to reduce unnecessary maintenance and associated outage time.

Area 3: Plant Auxiliaries

This area focuses on plant auxiliaries including the air heater, feedwater system, cooling water systems, electrical systems, etc. Plant auxiliaries cause approximately 1-2% of lost megawatt-hour (MWh) generation from our coal-fired plants over 20 years old. This can be improved to under 1% with restoration of critical components in this area of the plant. Some examples of recommendations for improved reliability and increased operating efficiencies in these areas are:

a. air heater or air heater basket replacement with the attendant modern sealing systems;
b. improved air heater surface design and cleaning system installation to address fouling;
c. feedwater heater retubing or replacement with upgraded materials to reduce failure rates; and
d. cooling tower fill improvements.

Area 4: Environmental (Focus on Electrostatic Precipitators)

Precipitator performance has the fourth largest impact on loss of plant availability. This problem almost always manifests itself in the form of load curtailment caused by the potential for opacity excursions. To exacerbate the problem, these curtailments typically occur at very critical capacity supply situations such as periods with high load requirements. Recommendations for mitigation are:

a. collection plate and electrode upgrades and/or replacement;
b. collection surface additions (new fields);
c. various flue gas treatment system installations;
d. addition of modern control system installations; and
e. general correction of leakage and corrosion problems.

Area 5: Fuel Flexibility

Many utilities have expanded their coal purchase specifications to leverage the variability in the cost of coal as a means of providing low-cost electricity to their customers. This practice, however, can have an adverse affect on plant reliability due to stress on the plant. It should be noted that although this area is not statistically recognized as a cause of loss of plant availability, fuel related problems are a major part of loss of availability from Area 1 "boiler/steam generator" due to such phenomena as boiler slagging/fouling, limited pulverizer throughput, reduced coal grindability, inadequate primary air systems, etc. Recommendations to reduce or eliminate these limitations are:

a. coal handling system upgrades to accommodate lower Btu coal;
b. mill upgrades to accommodate reduced grindability of coal;
c. ash (bottom and/or fly) system upgrades to accommodate higher ash coal or different ash classes;
d. additional furnace-cleaning equipment to mitigate different slagging and fouling characteristics of the coals;
e. draft system upgrades including FD fans, ID fans, combustion air temperature, and related electrical systems to accommodate higher gas volume flow rates; and

f. precipitator upgrades to accommodate changes in fly ash resistivity and/or quantity.

Area 6: Boiler Water Treatment

This issue goes hand-in-hand with Area 1 described above. Performance of boiler heat transfer surface is highly dependent on the chemistry of the water/stream that keeps the surface cool. Upgrades of the boiler water treatment system should be coordinated with the upgrades described in Area 1. An added benefit of higher water purity standards is faster plant start-ups; and, therefore, a unit can come on-line more quickly and ramp up generation faster resulting in a higher overall generation output. In addition, water purity has a cascading effect increasing the reliability of feedwater heaters and turbine blades and improving condenser performance.

Area 7: Controls and Plant Diagnostic Systems

Modern digital control and diagnostic systems can improve heat rates (generation efficiency), lower emissions, reduce plant startup times, and provide valuable information for outage planning. Recommendations in this regard include:

a. replacement of outdated analog control with advanced digital control systems;
b. replacement and/or addition of instrumentation for better control of the unit over a wider range of loads and improved monitoring of critical system components for outage planning;
c. installation of plant diagnostic and data acquisition systems to perform predictive maintenance reducing unplanned outages and extending on-line time durations between planned outages; and
d. installation of turbine bypass system hardware and controls to facilitate lower load capabilities, faster unit start-ups and faster ramp rates increasing overall unit productivity.

Area 8: Plant Heat Rejection

For many plants, the highest capacity requirements of the year occur at the same time that they experience severe heat rejection limitations. Summertime cooling lake and river temperatures/water levels can cause load curtailments. Recommendations include:

a. water intake structure modifications to provide more flexibility during low water levels;
b. cooling tower additions to provide an alternate heat rejection mechanism; and
c. cooling lake design modifications (additional surface, redirected flow path, etc.) to increase heat rejection capability.

Summary

Restoration of our 20+-year-old coal-fired plants to a condition similar to those that are under 20 years through the recommendations described in these eight areas can create approximately 10,000 MWs of additional availability from existing assets. We would expect this number to grow significantly as we increase utilization of our older plants to meet growing demand. Without implementing these recommendations, the forecasted increases in utilization will accelerate failures in these older facilities increasing the need for the recommendations we have identified here.

Of particular interest is that 90% of the increased availability identified will come from component replacement and other projects involving the boiler/steam generator. The boiler/steam generator has been the focus of the EPA's allegations in its recent reinterpretation of the New Source Review program as part of its power plant enforcement initiative.

Increasing Generation Output of Existing Units

The maximum demonstrated generating capacity (MDGC) of coal units older than 20 years, as identified above, is conservatively estimated to total approximately 220,000 MWs. The existing operating capacity is estimated to be 200,000 MWs (due to deratings). This group of plants has the potential for both capacity restoration (20,000 MWs) and/or capacity maximization (20,000 MWs). Thus, the total amount of potential increased MW output of this existing group of units is approximately 40,000 MWs. This increased capacity could be achieved within 36 months.

If all existing conditions resulting in a derating could be addressed, approximately 20,000 MWs of increased capacity could be obtained from regaining lost capacity due to unit deratings. This increase would be achieved using the approaches and techniques in Table 1 below.

Approximately an additional 20,000 MWs of capacity could be gained if it were possible to increase heat input and/or electrical output from generating equipment while still maintaining the acceptable design margins and allowable code ratings of the equipment. The approaches and techniques would be similar to those for regaining capacity, as indicated in Table 1.

These approaches and techniques could only be logically pursued by the facility owners if it was clearly understood that the increased availability and/or electrical output would not trigger New Source Review (NSR) and if repowering or construction of new clean coal technologies would be subject to the streamlined permitting authorized by the 1990 CAA Amendments.

The techniques to recover lost capacity and to increase capacity above MDGC have been collected from a combination of research studies by utility industry organizations (such as EPRI) and actual case studies (such as those outlined below) which had benefits for plant owners. They are summarized in Table 1 below.

TABLE 1
Techniques and Approaches for Coal-Fired Power Plants Capacity Restoration and Increase

Capacity Increase Method	Capacity Restoration	Efficiency/ Capacity Increase	Fuel Conversion/ Repowering
Installation of improved air pollution control equipment	X	X	X
Steam turbine modernization improvements and upgrades	X	X	
Coal washing	X	X	
Coal switching	X	X	
Repowering with CFB technology			X
Consolidation of multiple, smaller inefficient units to larger, more efficient units		X	X
Operating above the nameplate but within the plant design	X	X	
Control system improvements	X	X	
Plant efficiency improvements	X	X	

The techniques and approaches listed in Table 1 have been implemented with proven results. The following highlights are from case studies.

?? *SCR and FGD emissions control equipment was installed on a coal- fired generating station to reduce emissions of SOx and NOx. In order to offset the increased auxiliary load (16 MWs) of these new systems, an upgrade of the original 500-MW (nominal rating) steam turbine was performed. The upgrade consisted primarily of a new high-efficiency, high-pressure rotor with increased number of stages and an optimized steam path. The upgrade resulted in an output increase of approximately 15 MWs, almost offsetting the auxiliary load increase from the new emission controls.*

?? *Turbine upgrades were completed on two 400-MW rated units to obtain an additional 25 MWs per unit. No additional steam was required from the boiler. No changes were made to the boiler. A more aerodynamic steam path through the turbine was designed and installed.*

?? *Turbine upgrades were incorporated into another unit, nominally rated at 500 MWs achieving an additional 25 MWs. In this case, more steam had to be generated in the boiler and the steam turbine was upgraded.*

?? *Coal cleaning is a process whereby a coal that is high in ash and sulfur is "washed." As a result, the coal is lower in both ash and sulfur content and higher in thermal value. The method consists of a multi-circuit wet process where water is used for screening and separation. Coal cleaning is a cost-effective means of separating ash and sulfur from coal, which in turn reduces opacity and SO_2 emissions. This enables one facility to continue to use local, lower cost, higher ash and sulfur coal and meet environmental limits. Without this coal cleaning process, the facility's load would be limited by approximately 10% due to opacity restrictions.*

?? *Coal switching is an alternative to coal cleaning. In some cases where coal has been switched to reduce SOx emissions, the capacity may be impaired unless fuel handling systems are upgraded to allow efficient use of lower sulfur fuels.*

?? *Repowering with CFB technology is an alternative to installing NOx and SOx emissions equipment. The use of this technique is highly site and fuel specific.*

?? *Capacity increases can be accomplished by taking a brownfield site with several smaller old units, and repowering the site with a single large unit. This will require the full environmental permitting*

process. It is a technique that is highly site specific and economically driven. To make the economics attractive, it is important that the units are running at low dispatch levels, so income losses are minimized, and the site can be readily cleared for construction of the larger unit.

?? *Control system improvements can increase capacity in older plants. Modern control systems can improve efficiency and reduce emissions by optimizing the combustion process. General improvements to plant efficiency can be obtained by improved operating and maintenance practices along with targeted equipment improvements.*

Note: The additional 20,000 MW that can be achieved by capacity restoration described in this section includes the 10,000 MW of capacity that can be recovered due to deteriorated availability described earlier in the report.

Opportunities for Greenfield Sites and Repowering Existing Facilities with Pulverized Coal Power Generation

As a result of ongoing technology development, new and retrofitted pulverized coal power plants have achieved outstanding emissions performance for NOx, SOx, and particulates. Similarly, continued advances in the steam cycle continue to provide higher net plant efficiencies. As a result, new pulverized coal-fired power plants are now commercially available with minimal emissions and with very favorable total production cost. Repowering of an old existing coal-fired power plant with a single modern generating unit equipped with commercially proven emissions controls results in significant reductions in total tons of emissions, even while substantially increasing the total megawatt-hour output of the facility. A case study of repowering an actual old coal-fired plant with a unit utilizing current technology showed a 32% higher design capacity, achieving triple the total electrical output, an 87% reduction in tons of NOx and SOx up the stack, and a 42% reduction in total electricity production costs.

Pulverized Coal Technology Options

The configuration of today's state-of-the-art pulverized coal power plant is primarily dependent on the sulfur quantity of the coal to be utilized.

Low sulfur coals will most economically utilize a dry scrubber and baghouse for SO_2 and particulate control. Wet scrubbers can also be utilized with the benefit of producing a useful byproduct (gypsum).

Higher sulfur coals will utilize a wet scrubber and precipitator or baghouse for SO_2 and particulate control.

NOx emissions will be controlled by both Low NOx Burners (LNB)and Selective Catalytic Reduction (SCR).

The boiler/turbine steam cycle will vary from a standard subcritical cycle to an advanced supercritical cycle depending on project requirements and fuel costs.

Example: Low Sulfur Coal Configuration with representative emissions performance.

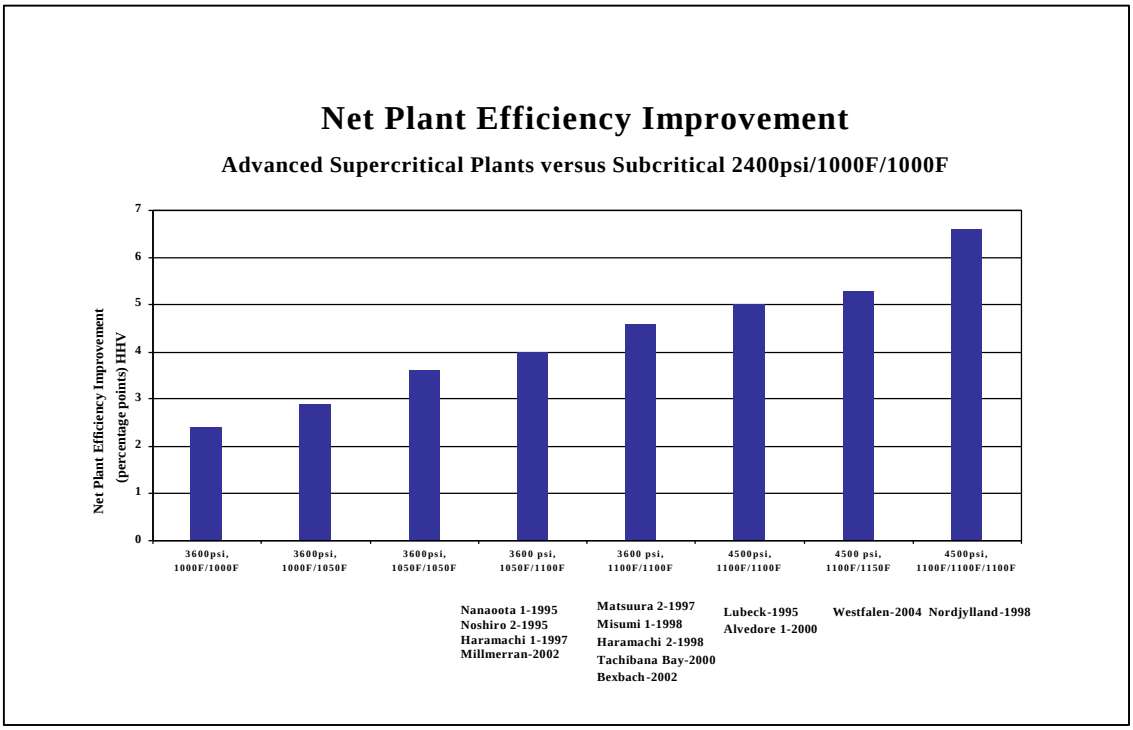
Boiler	SCR	Dry Scrubber	Baghouse
Subcritical or Supercritical	90% + NOx Removal NOx = 0.15 lb/MWh	90-95% SO_2 Removal SO_2 < 0.25 lb/MBtu	Particulate 0.03 lb/MBtu

Example: High Sulfur Coal Configuration with representative emissions performance.

Boiler	SCR	Precipitator or Baghouse	Wet Scrubber
Subcritical or Supercritical	90% + NOx Removal NOx = 0.15 lb/MWh	Particulate 0.03 lb/MBtu	95%+ SO_2 Removal SO_2 = 0.25 lb/MBtu

Heat Rate

Over the last 10 years, higher efficiency pulverized coal plants have been placed in commercial operation. The higher efficiencies are due not only to advanced pressure and steam cycles, but also to improvements in turbines and reductions in auxiliary power requirements. Pulverized coal power plant heat rate improvements versus steam parameters are shown below. (The actual operating plants have steam parameters close to the examples under which they are listed.)



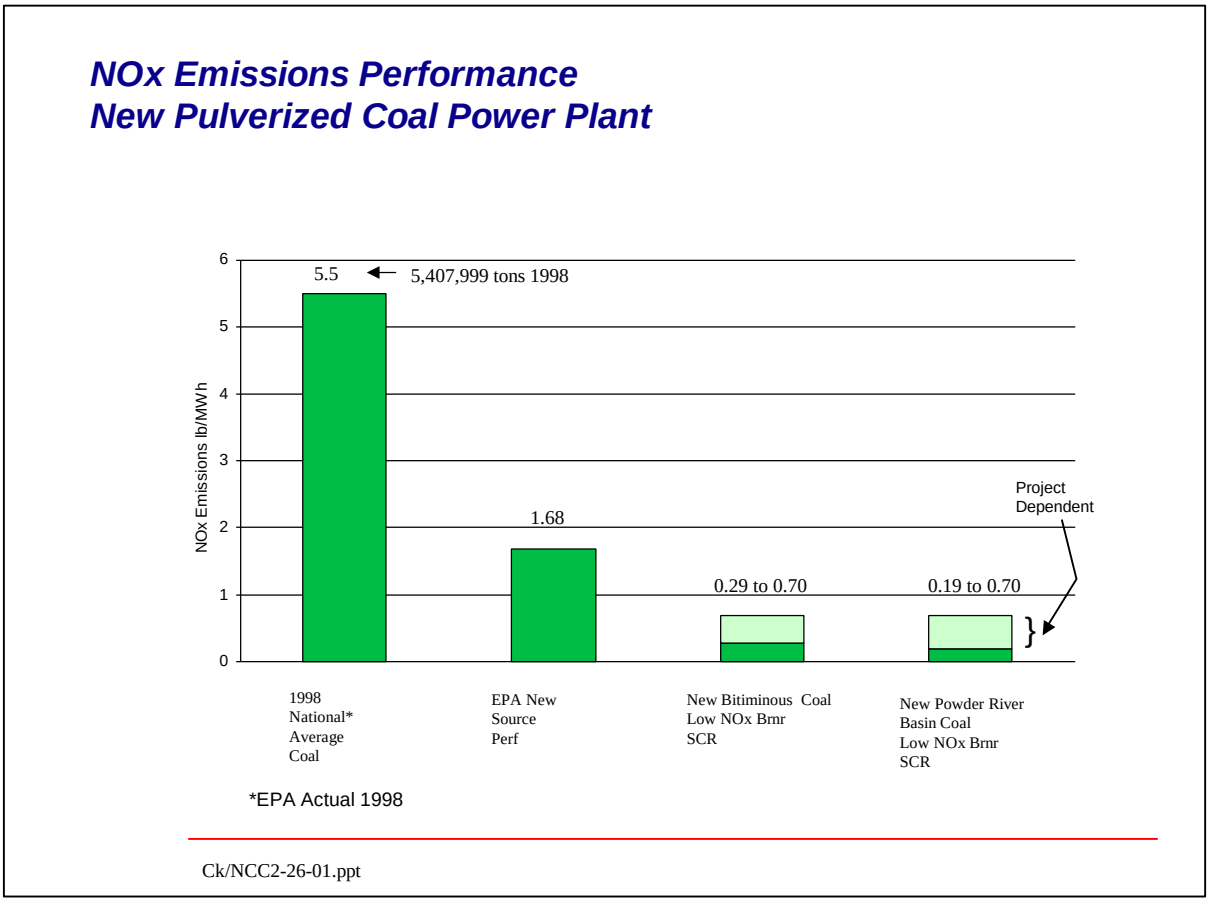
The summary point is that higher efficiency cycles are now being demonstrated with commercially required availability/reliability. Higher efficiency cycles will reduce the production cost by reduced fuel consumption and will result in a lower capital cost for all of the environmental equipment (on a $/kW cost basis). The ambient air emissions levels (NOx, SOx, particulate, and mercury) will primarily be a function of the emissions control devices installed (SCR, scrubber, baghouse, etc.). More efficient plants will provide an emissions reduction as well. For the U.S. market, the economically optimum cycle efficiency will be very project specific. However, today's advanced cycles have been demonstrated commercially and can be applied where project economics dictate.

Emissions Performance

NOx

Significant improvements in NOx emissions are being achieved in pulverized coal-fired power plants today. This is through both advances in Low NOx Burner Combustion technology and advances in Selective Catalytic Reduction systems, both of which are being widely applied. Low NOx Burner Combustion technology has resulted in combustion NOx levels being in the range of 0.15 to 0.30 lb/MBtu, depending on the coal. Selective catalytic reduction systems are in operation with NOx removal efficiencies up to 90-95%. An existing plant retrofit this year with an SCR will result in NOx emissions of approximately 0.30 lb/MWh, (approximately .03 lb/MBtu which is lower than the best natural gas combined cycle unit utilizing dry Low NOx Combustion, according to the most recent EPA actual operating data).

New pulverized coal power plants, through the application of commercially demonstrated Low NOx Burners and SCRs, can achieve NOx emissions as shown in the table below. In order to compare NOx emissions with natural gas-based power generation, the performance is reported in lb NOx per MWh.

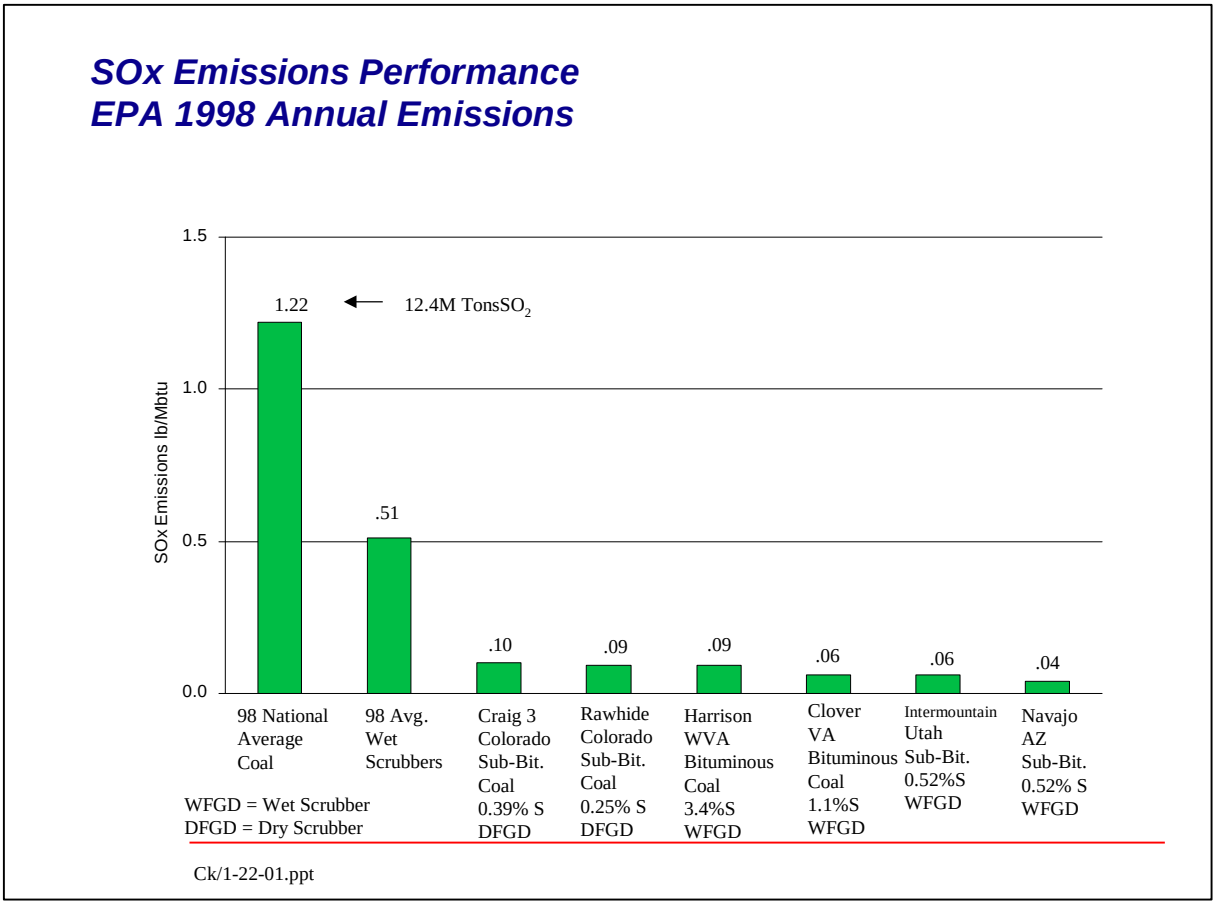


The NOx emissions performance represented in this section of the report and in the two case studies is derived from applying the state of the technology, Low NOx Burners, with the state of the technology Selective Catalytic Reduction Controls. These are applied to representative Eastern and Western coals and typical project parameters. The actual NOx emissions that can be obtained from a given new coal-fired project will depend on the analysis of the actual coal to be burned. It will also depend to some extent on the local ambient air conditions and condenser water availability and temperatures, which will impact the available heat rate of the cycle. The actual achievable NOx emissions rate for a given project can only be determined after the specific project and fuel parameters have been defined.

It should also be noted that this section of the report only addresses new, coal-fired generating plants. Whereas significant NOx reductions can be achieved from retrofits to an existing coal-fired generating unit, in many cases constraints from the original furnace design or other project constraints that cannot be modified will result in it not being possible to achieve the same NOx reductions on a retrofit as will be available for a greenfield generating unit that has maximum design flexibility for the boiler and environmental equipment.

SOx

Similarly, outstanding performance is being demonstrated on low SOx emissions technology, from a number of pulverized coal-fired power plants ranging from high sulfur Eastern bituminous coals to low sulfur Western coals. The graph shown below reflects actual SOx emissions from a number of coal-based power generating facilities as reported in the EPA 1998 Annual Emissions. In summary, the technology is available and is being commercially demonstrated to achieve extremely low SO_2 emissions.



Particulate
High efficiency precipitators and baghouses are routinely achieving particulate emissions levels under .020 lb/MBtu.

Mercury
Significant mercury removal research from pulverized coal power plants has been underway over the last 10 years. In 2001, this will culminate in plant demonstrations for Advanced Mercury Removal Systems at Alabama Power's Gaston Station, Michigan South Central's Endicott Station, and Cinergy's Zimmer Station. These demonstrations are aimed at positioning coal-fired power plants for the announced future regulation of mercury emissions. Additionally, aggressive research and plant demonstrations are underway to substantially reduce mercury emissions.

Pulverized Coal Power Plant Applications

Following are two cases, which illustrate the impact of building new pulverized coal power generation plants.

1. Greenfield site or addition of a new generating unit to an existing power plant. This case shows typical plant efficiencies, emissions levels, electricity produced, and production costs for new pulverized coal power plants for both a low and high sulfur coal options.

2. Repowering of an old existing pulverized coal-fired power plant.

This case examines the performance emissions and production cost of repowering an entire old, coal-fired power plant consisting of multiple old, low-efficiency units that have high emissions rates with a single modern pulverized coal-fired generating unit.

Case 1

This case examines the efficiency, emissions performance, and production cost for adding a new coal-fired generating unit, either to a Greenfield site or to an existing power plant. Performance is shown for both an eastern bituminous coal and a Powder River Basin Coal Plant.

TABLE 2
New Pulverized Coal Power Plant

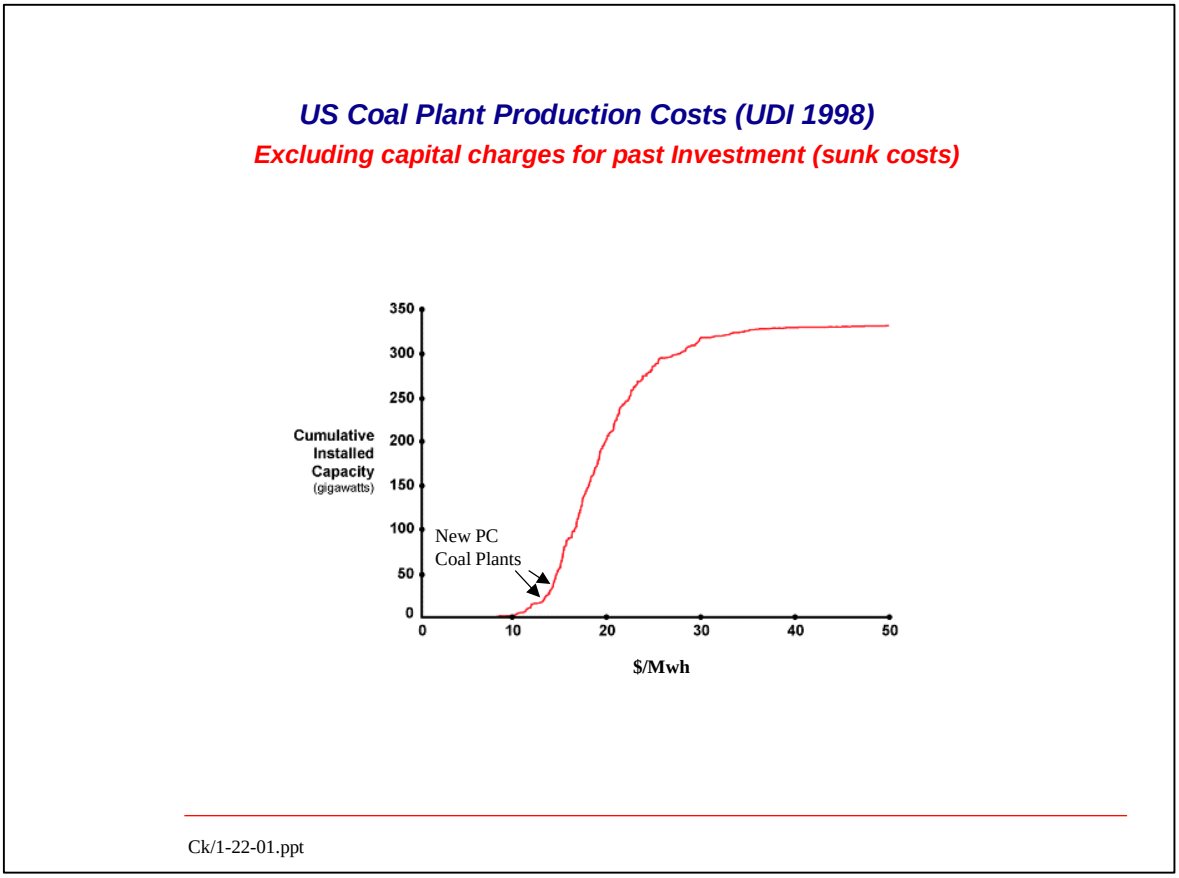
		Low Sulfur PRB Coal		High Sulfur Bit. Coal	
Coal Heating Value	Btu/lb	8,000		12,500	
Coal % Sulfur	%	0.4		3.5	
Steam/Turbine Cycle		Supercritical	Subcritical	Supercritical	Subcritical
Net Plant Heat Rate	Btu/kWh	8900	9600	8500	9200
Net Plant Efficiency	HHV	38.3%	35.6%	40.1%	37.1%
Net Plant Efficiency	LHV	41.6%	39.8%	42.2%	39.0%
Emissions - Ranges					
Combustion NOx	lb/Mbtu	0.20 to 0.40	same	0.40 to 0.50	same
SCR % NOx Removal	%	80 to 90	same	85 to 92	same
Outlet NOx	lb/Mbtu	0.020 to .080	same	0.032 to .075	same
Outlet NOx @ 3% 0_2	ppm	14 to 58	same	23 to 54	same
Outlet NOx @ 15% 0_2	ppm	5 to 20	same	8 to 18	same
Outlet NOx	lb/MWh	.18 to .70	.19 to .75	.28 to .66	.29 to .69
Uncontrolled SO_2	lb/Mbtu	1.0	same	5.6	same
Scrubber % SO_2 Removal	%	90	same	95	same
Outlet SO_2	lb/Mbtu	.10	same	.28	same
Outlet SO_2	lb/MWh	.89	.96	2.38	2.58
Coal Cost	$/MBtu	1.22	1.22	1.22	1.22
Fuel Production Cost	$/MWh	10.86	11.71	10.37	11.22
Non-Fuel O&M Cost	$/MWh	3.50	3.50	3.50	3.50
Total Production Cost	$/MWh	14.36	15.21	13.87	14.72

Total Production Cost
The curve below shows the variable production cost (Fuel + O&M, excluding capital investment costs) for all the coal-fired power plants in the U.S. in 1998 (UDI data).

The curve is a plot of the variable production cost of every coal-fired power plant, ranked from the lowest to the highest. It only shows the fuel and O&M cost, and not the sunk capital costs. This would also indicate the relative order of competitive dispatch.

Also shown on the curve is the variable production cost for the two plants discussed in the case studies. This shows that the total production costs for a new pulverized coal plant will be significantly lower than most of the existing coal fleet and will assure high capacity factors.

Case 1



Total Emissions Level
The total NOx and SOx emissions are significantly lower than what is being achieved in the existing coal-fired power plants today.

Total Emissions Performance
Table 3 (below) places a value on the total NOx and SOx emissions based on assumed allowance values for the examples in this case. To illustrate the low emissions level, the total outlet NOx and SOx emissions are given a monetary cost based on assumed allowance costs. When the emissions costs are stated as a production cost in $/MWh, it can be seen that these do not change the very favorable total production cost of electricity.

TABLE 3

		Low Sulfur PRB Coal		Eastern Bituminous Coal	
		Supercritical	Subcritical	Supercritical	Subcritical
NOx Allowance Value (assumed)	$/ton	1000	1000	1000	1000
Outlet NOx	lb/MWh	.18	.19	.28	.29
NOx Allowance Cost	$/MWh	.09	.10	.14	.15
SOx Allowance Value (assumed)	$/ton	200	200	200	200
Outlet SO_2	lb/MWh	.89	.96	2.38	2.58
SOx Allowance Cost	$/MWh	.09	.10	.24	.26
Total Emission Allowance Cost	$/MWh	.18	.20	.38	.41

Case 2: Coal Power Plant Repowering

This case considers the repowering of an existing Eastern U.S. coal-fired power plant, burning low sulfur Eastern bituminous coal. The plant consists of six generating units that were built between 1949 and 1956, with a composite average net plant efficiency of 29.4%. The total gross generating capacity from all six units is 387 MW. The plant has no emission controls for NOx and SOx except for Low NOx Burners on one of the units.

The plant is repowered by replacing the boiler and turbine islands for all six units with a single 506-MW supercritical boiler/turbine, with an average net plant efficiency of 38.8%. The plant's coal receiving and handling, ash disposal, and electrical distribution infrastructure is retained where possible. The repowered unit is redesigned for the same heat input as the original six units; Low NOx Burners, an SCR, a dry SO_2 scrubber, and baghouse are added. The same coal is used in the repowered unit as is currently being burned.

Table 4 shows the actual operating performance from this plant for 1998 and the projected repowered performance in 2004.

In summary, with the plant repowered at the same heat input, it will now be rated at 31% higher megawatt output and operating efficiency. Both the NOx and SOx emissions will be reduced by 87% of the actual 1998 emissions in tons. The total production cost per megawatt-hour will be reduced 42%. Because of the low production cost, the unit will be base loaded with a high capacity factor, which will result in more than triple the actual megawatt hours produced during the year.

TABLE 4
Case 2
Repowering Existing Coal Plant

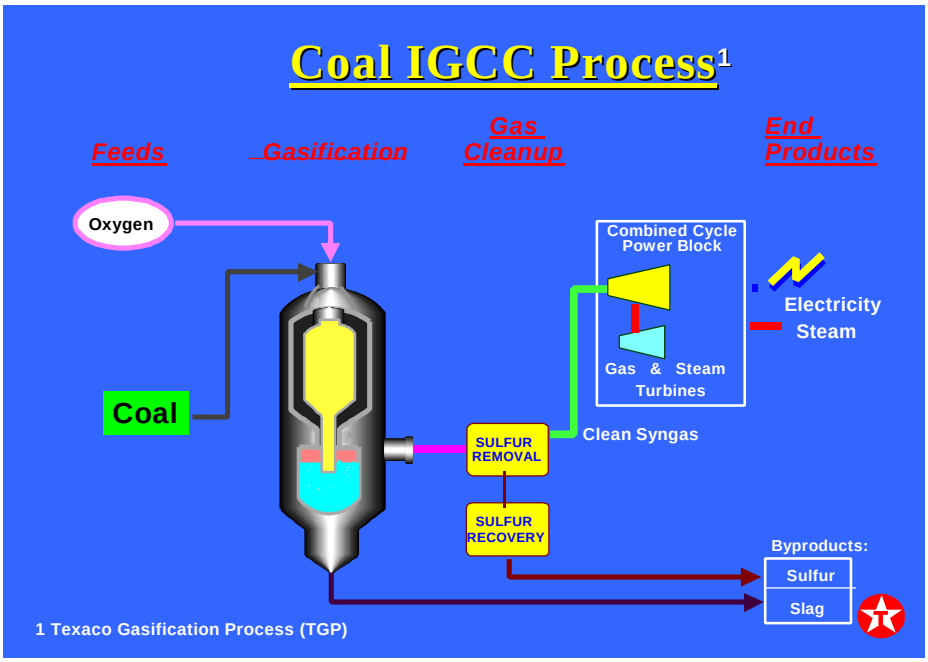
	Existing Plant 1998 Actual Operating Data	Repowered 2004 Performance	Improvement %
Design Plant Total Heat Input MBtu/hr	4140	4140	
Nameplate MW	387	506	
Total # of Units	6	1	
Total Actual MWh	1,082,180	3,544,296	+327%
Total Actual Capacity Factor	31%	85%	
Heat Rate – Annual Average Btu/kWh	11,594	8,800	
Average Plant Efficiency HHV	29.4%	38.8%	+32%
Average Plant Efficiency LHV	30.9%	40.8%	
NOx Tons – annual	3536	468	-87%
NOx Emission Rate lb/MBtu	0.509	.03	
NOx Emissions Rate lb/MWh	5.9	0.26	
Coal % S	1.08	1.08	
SOx Tons Annual	12,881	1565	-88%
SOx Emissions Rate lb/MWh	23.8	0.88	
Fuel Cost $/MBtu	1.05	1.05	
Fuel Production Cost Annual Avg $/MWh	12.18	9.26	
Non-Fuel (OEM) Production Cost Annual Average $/MWh	9.87	3.57	
Total Production Cost $/MWh	$22.04	$12.83	-42%

Opportunities for Greenfield Sites and Repowering Existing Facilities with Coal-Based Power Generation

When considering coal-based technologies for both greenfield applications and repowering of existing facilities, utilities have several primary options to consider. In addition to the modern pulverized coal technologies described earlier, integrated gasification combined cycle (IGCC) has become a viable, commercially available technology. With successes from the Clean Coal Technology Program in both new and repowered projects, much has been learned about IGCC performance, heat rate, cost, and emissions performance. This information, which has been widely published, has become an important tool for evaluation of this technology by electric utilities.

IGCC Technology Options

The diagram below shows a typical IGCC plant. The coal gasification process replaces the conventional coal-burning boiler with a gasifier, producing syngas (hydrogen and carbon monoxide) that is cleaned of its sulfur and particulate matter, and used as fuel in a gas turbine. The power generation cycle is completed through the use of the Heat Recovery Steam Generator (HRSG) and steam turbine, just as in a natural gas-fired combined cycle (NGCC) plant, offering the high efficiency and continual advances achieved with this equipment configuration.



The two primary technologies which have had the most success in the U.S. are Texaco's oxygen-blown, entrained-flow gasifier (Tampa Electric Company's Polk Power Station, a greenfield plant) and the Global Energy E-Gas (formerly Destec) oxygen-blown, entrained-flow gasifier (Cinergy/PSI Energy's Wabash River Station, a repowering project at an existing power plant).

In the Texaco gasification process, a down-flow slurry of coal, water, and oxygen, are reacted in the process burner at high temperature and pressure to produce a medium-temperature syngas. The syngas moves from the gasifier to a high-temperature heat recovery unit, which cools the syngas while generating

high-pressure steam. The cooled gases flow to a water wash for particulate removal. Molten ash flows out of the bottom of the gasifier into a water-filled sump where it is forms an inert solid slag. Next, a COS hydrolysis reactor converts COS into hydrogen sulfide. The syngas is then further cooled in a series of heat exchangers before entering a conventional amine-based acid gas removal system where the hydrogen sulfide is removed. The sulfur may be recovered as sulfuric acid or molten sulfur. The cleaned gas is then reheated and sent to a combined-cycle system for power generation.

The Global Energy E-Gas process uses a slurry of coal and water in a two-stage, pressurized, upflow, entrained-flow slagging gasifier. About 75% of the total slurry is fed to the first (or bottom) stage of the gasifier. All the oxygen is used to gasify this portion of the slurry. This stage is best described as a horizontal cylinder with two horizontally opposed burners. The gasification/oxidation reactions take place at temperatures of 2,400 to 2,600^{o}F. Molten ash falls through a tap hole at the bottom of the first stage into a water quench, forming an inert vitreous slag. The hot raw gas from the first stage enters the second (top) stage, which is a vertical cylinder perpendicular to the first stage. The remaining 25% of the coal slurry is injected into this hot raw gas. The endothermic gasification/devolatilization reaction in this stage reduces the final gas temperature to about 1,900^{o}F. The 1,900^{o}F hot gas leaving the gasifier is cooled in the fire-tube product gas cooler to 1,100^{o}F, generating saturated steam for the steam power cycle in the process.

Particulates are removed in a hot/dry filter and recycled to the gasifier. The syngas is further cooled in a series of heat exchangers. The syngas is water scrubbed to remove chlorides and passed through a COS hydrolysis unit. Hydrogen sulfide is removed in the acid gas columns. A Claus unit is used to produce elemental sulfur as a salable by-product. The clean syngas is then moisturized, preheated, and sent to the power block.

In Europe, Global Energy has successfully used the British Gas/Lurgi (BGL) gasification process. In the BGL process, the gasifier is supplied with steam, oxygen, limestone flux, and coal. During the gasification process, the oxygen and steam react with the coal and limestone flux to produce a raw coal-derived fuel gas rich in hydrogen and carbon monoxide. Raw fuel gas exiting the gasifier is washed and cooled. Hydrogen sulfide and other sulfur compounds are removed. Elemental sulfur is reclaimed and sold as a by-product. Tars, oils, and dust are recycled to the gasifier. The resulting clean, medium-Btu fuel gas is sent to a gas turbine. Based on the success of the BGL process at the Schwarze Pumpe GmbH plant in Germany, Global Energy is building two plants in the U.S. The 400-MW Kentucky Pioneer Project and the 540-MW Lima Energy Project will both use BGL gasification of coal and municipal solid waste to produce electric power. The Kentucky project is being partially funded by DOE.

Heat Rate

DOE reports the Polk Power Station heat rate to be 9,350 Btu/kWh, with Wabash River at 8,910 Btu/kWh. These equate to about 38.4% and 40.2% (LHV) respectively. Overall IGCC plant efficiency of 45% LHV is likely to be demonstrated with the enhancements developed from the Clean Coal Technology Program projects and continued advances in gas turbine technology. As part of its Vision 21 Program, DOE has set a 2008 performance target of 52% on an HHV basis (about 55% LHV) for IGCC.

Emissions Performance

With gas becoming the fuel of choice for most new units, permitting agencies and environmental groups have become used to seeing very low emission limits for new units. Further, they have come to expect that repowering existing units should also meet those same low levels, regardless of economics or fuel choice. IGCC can approach the environmental performance of natural gas-fired power plants, opening the door for its application in new and repowered plants. As part of the Vision 21 Program, DOE has set a

2008 performance target of 0.06 lb/mmBtu for SO_2, 0.06 lb/mmBtu for NOx, and 0.003 lb/mmBtu for particulate matter.

Conventional power plants that are candidates for repowering are typically 40-50 years old. Historically, the small upgrades and modifications that were made to maintain capacity or increase efficiency did not subject the utility to the New Source Review (NSR) process. With EPA's coal-fired power plants enforcement activities, many utilities are under enforcement pressure to meet very strict NSR limitations for SO_2, NOx, and particulates. Compliance with these limitations usually means retrofit with flue gas desulfurization (FGD) for SO_2 control, selective catalytic reduction (SCR) for NOx control, and possibly even upgrades to the electrostatic precipitator for increased particulate control. With such units being near the end of their economically useful lives, adding additional controls may not make economic sense for a unit that may be shut down in a few years.

Repowering with IGCC allows the utility to maintain or increase capacity, while significantly improving environmental performance and producing low-cost power. The coal gasification process takes place in a reducing atmosphere at high pressures. In the gasifier, the sulfur in the coal forms hydrogen sulfide, which is easily removed in a conventional amine-type acid gas removal system. The concentrated hydrogen sulfide stream can then be recovered as elemental sulfur or sulfuric acid, and sold as a commercial byproduct, eliminating the need to dispose of large amounts of combustion byproducts. The clean syngas is sent to the gas turbine to be burned. With the addition of nitrogen into the turbine for power augmentation, the combustion flame is cooled, minimizing NOx formation and eliminating the need for SCR.

Many existing coal-fired plants are also affected by the NOx SIP call, and utilities are facing the installation of SCR on these existing units in order to comply. With changes in utility regulation, and the age of the units, the economics of these retrofits presents a challenge to continued operation of the units. Further, the possibility of stricter limitations on SO_2 or other emissions in the next few years presents another layer of economic decisions. While the unit may still be economic to dispatch following the installation of SCR, the addition of FGD may not allow that to continue. In that case, the utility would face the stranding of its SCR assets after only a few years of operation. Repowering with IGCC would provide the utility with the ability to maintain or even increase capacity, meet NOx limitations, and prepare for stricter SO_2 emission limitations.

While the retrofit of emission controls reduces emissions, it leads to secondary environmental issues, such as the large amounts of land needed to dispose of the new FGD byproduct and groundwater protection. The SCR system raises issues regarding local exposure to risks of accidental release of ammonia and disposal of the SCR catalyst.

In the gasifier, the ash in the coal melts, and is recovered as a glassy, low permeability slag which can be sold for use in making roofing shingles, as an aggregate, for sandblasting grit, and as an asphalt filler. With the sulfur also recovered as a commercial byproduct, repowering with IGCC can eliminate the solid waste issues that utilities might face when retrofitting conventional coal-fired plants with FGD and SCR.

With EPA's recent determination to regulate mercury emissions from coal-fired units, utilities will face additional potential requirements for the retrofit of control equipment. With the reducing atmosphere, and by operating a closed system at high pressures, IGCC releases of mercury are minimized. Initial information from EPA's mercury-based Information Collection Request shows promising results for IGCC, with as much as 50% of the mercury in the coal feedstock reduced or removed, much of it bound in the slag and sulfur byproducts.

Another issue that utilities will potentially face in the near future is the need to reduce CO_2 emissions. The existing coal-fired fleet in the U.S. is responsible for about one-third of all of the CO_2 emissions. While automobiles and other industries make up a large portion of U.S. CO_2 emissions, coal-fired power plants are an easier target to identify, measure, and control. Due to its high overall efficiency, repowering an existing coal-fired power plant with IGCC can reduce CO_2 emissions by as much as 20%.

Overall, repowering with IGCC provides a utility with significant increases in environmental performance. By reducing SO_2 and NOx emissions, minimizing solid waste disposal issues, and addressing potential near-term emission limitations for mercury and CO_2, repowering with IGCC allows the utility to move forward with the knowledge that it has addressed environmental issues effectively. For capacity additions and repowering over the next five years, IGCC is an option that utilities can seriously consider.

IGCC Power Plant Applications

Recent History and Applications

Coal gasification technology has been used for over a hundred years. The production of town gas worldwide is a simple form of gasification. Coupling this proven technology with efficient combined cycle technology was seen as a way to enjoy the advantages of using low-cost coal with the high efficiency of combined cycle technology. The 100-MW Cool Water IGCC project, which went in service in 1984, was the first commercial-scale demonstration of IGCC. That project was done in a consortium of EPRI, Southern California Edison, Texaco, GE, Bechtel, and others. The plant operated for more than four years, achieving good performance, low emissions, and developing a base of design for full-scale IGCC plants.

Since then, IGCC technology has improved greatly through DOE's Clean Coal Technology program. The Wabash River IGCC Project and Polk Power Station IGCC Project are in operation as a part of this program. Installations in other countries include the Buggenum plant in the Netherlands and the Puertollano plant in Spain. IGCC performance and reliability continues to see significant improvements. In the fourth year of operation of Tampa Electric's Polk Power Station, the gasifier had an on-stream factor of almost 80%, a considerable improvement over previous years. This project no longer suffers from the serious problems encountered over the first three years, including convective syngas cooler pluggage, piping erosion and corrosion, and sulfur removal problems. The on-going pluggage problems in the convective syngas coolers have been resolved by modifying start-up procedures to minimize sticky ash deposits, and by making configuration changes in the inlet to the coolers to reduce ash impingement at the tube inlets. In the fourth year, the coal gasification portion of the plant became so reliable that the leading cause of unplanned downtime was not there, but rather in the distillate oil system for the gas turbine (problem has been addressed).

Reliable performance has also been achieved at the Wabash River plant. During 2000, the gasification plant reached 92.5% availability, with the power block at 95%. In fact, the gasification technology caused no plant downtime at all. Other areas of the plant, such as coal handling and the air separation unit were available more than 98% of the time.

IGCC for New and Repowered Plants

These examples show that IGCC has met the challenges of the Clean Coal Technology program. Further, with almost 4,000 MW of IGCC in operation worldwide, and another 3,000 MW planned to go into

operation over the next four years, this technology is commercially proven and ready for the repowering market.

The U.S. now has about 320,000 MW of coal-fired power plants, just over one-third of all installed capacity. These coal-fired power plants generate over half of all of the electricity in the U.S. Many of these plants are over 30 years old, with some over 50 years of age. With a growing need for additional capacity in many parts of the country, and rising operation and maintenance costs on existing units, many utilities are looking hard at repowering with technologies that can increase capacity, while decreasing operation and maintenance costs.

Repowering with IGCC can meet those challenges. Repowering older, less efficient generating units with IGCC, results in capacity increases, lower production costs, higher efficiency, and environmental compliance. Since the IGCC plant uses coal as its feedstock, much of the existing coal-fired plant's coal handling and steam turbine equipment and infrastructure can be utilized, lowering the overall cost of repowering. With greater than 95% of the sulfur emissions removed, and further improvements in combustion turbine low-NOx burner technology, emissions of SO_2 and NOx now approach the performance of NGCC plants. By using low-cost and/or low-quality coals, the cost of electricity generated from a plant repowered with IGCC technology can meet or beat that produced by NGCC plants.

One of the key efficiency advantages comes with oxygen-blown IGCC technology. In this type of gasification system, air is first separated into its main constituents: oxygen and nitrogen. The oxygen is used in the gasifier, and the nitrogen is injected into the gas turbine, where it increases the mass flow through the gas turbine, increasing power output, and minimizing NOx formation during combustion. Efficiency increases through further integration can be realized by using extraction air from the gas turbine in other areas of the plant. Since this extraction air leaves the gas turbine at high temperature and pressure, it can be used to preheat boiler feed water. After the heat is removed, the cooled air, still at high pressure, is used to feed the air separation unit, reducing the amount of energy expended there to compress air.

A typical method of repowering an existing unit is to remove the coal-fired boiler and replace it with a gas turbine, re-using the steam turbine in combined cycle mode. In a combined cycle plant, the steam turbine usually provides about one-third of the total output. In a recent study conducted for DOE, a large number of plants with twin 150 MW units were identified as good candidates for repowering. There, the utility could repower one of the units with two 170 MW natural gas-fired gas turbines. The steam produced by the HRSGs for these units would power the existing 150 MW steam turbine, for a total of almost 400 MW.

A typical F class gas turbine produces about 170 MW when firing natural gas. At high ambient temperatures, output may fall to only 150 MW. In an IGCC plant, the syngas is fired in the gas turbine along with the nitrogen, providing significantly higher overall mass flow over a wide range of ambient temperatures. When firing syngas, this same F class gas turbine produces about 20% more output, reaching 190 MW or more. This additional capacity from firing syngas is valuable when additional peaking power is needed during hot, summer days. The additional exhaust flow results in more steam production in the HRSG, making up for steam uses in the gasification area. By firing syngas, the overall capacity is increased to almost 550 MW, more than tripling the capacity of the unit. Repowering the twin 150-MW unit could increase the overall capacity from the original 300 MW to almost 1,100 MW.

While the typical repowering study targets coal-fired boilers, existing NGCC units also provide a technical and economic opportunity for repowering with IGCC. In the case of NGCC units presently firing natural gas, rising fuel costs have lead to increases in the cost of producing electricity. This

typically results in a lower capacity factor, and the unit generates fewer MW-hours and revenues. Given the inherent high efficiency of the gas turbines, and the ability to utilize low-cost coal, repowering with IGCC can turn an NGCC unit with a high dispatch price into a unit that dispatches at a much lower cost. As described above, the additional 20% capacity gained from firing syngas instead of natural gas can have significant economic value in areas where there is insufficient peaking power capacity.

IGCC technology has become a more attractive option for new capacity because:

?? the technology has been successfully demonstrated at commercial scale in the U.S. and worldwide;
?? the enhancements made by the companies operating these IGCC plants, as well as by the technology suppliers, have decreased the cost and complexity of IGCC, while at the same time substantially improving the efficiency and reliability; and
?? the price differential between natural gas and coal has risen sharply over the last year.

Economics

The ability to repower units and gain the capacity increases noted in the previous section is a major economic driver for repowering with IGCC. Another advantage of repowering with IGCC is the ability to reuse a significant amount of the existing infrastructure at the plant. Areas such as buildings, coal unloading, coal handling, plant water systems, condenser cooling water, transmission lines, and substation equipment can be incorporated into the repowered IGCC plant This helps to minimize the time for repowering and can reduce the overall cost by about 20%.

With uncertainty in the pace and extent of utility industry restructuring, as well as with changes in environmental regulations, utilities have been reluctant to make large capital expenditures for new capacity. Almost all of the capacity installed over the last few years has been natural gas-fired gas turbines and NGCC. With ongoing decreases in the cost per kW for NGCC technology, along with forecasts of low natural gas prices, NGCC has been the choice for almost all of the new planned baseload capacity in the U.S. Most of this new generation has been built and is being planned in states that have completed their electric utility industry restructuring, making for easier entry into power markets. Unfortunately, the greatest needs for new generation have been in California and the Southeast where deregulation has either been incomplete, inconsistent, or delayed.

With recent increases in the price of natural gas, and stability or even decreases in coal costs, the electric utility industry has renewed its interest in coal-based technologies. Announcements by Tucson Electric Power and Wisconsin Electric Power to build the first coal-fired power plants in years puts coal back in the picture for new capacity. One important result of the improved performance of existing IGCC plants has been an overall decrease in second-generation IGCC plant capital costs. If the current differential price between coal and natural gas continues or grows larger, the economics for repowering with IGCC will become even more attractive.

In the paper "EPRI Analysis of Innovative Fossil Fuel Cycles Incorporating CO_2 Removal," various power generation technologies were analyzed with and without CO_2 removal systems, in a study performed by Parsons. The allowable capital costs were analyzed to determine a break-even cost of electricity based on a range of gas prices. For IGCC, the break-even point with $5/mmBtu gas was found to be about $1,200/kW, dropping to about $1,000/kW with $4/mmBtu gas prices. As IGCC plant costs continue to decrease, it will become an even more serious choice for repowering. If CO_2 removal is required in the future, the costs shown in the study for CO_2 removal

and the cost of producing electricity from IGCC will be competitive with NGCC at gas prices of only $3.70-4.00/mmBtu.

Reducing Regulatory Barriers

The Clean Air Act ("CAA") imposes a number of regulatory burdens on the expansion of electric generating capacity. EPA's recent interpretations of several existing laws have led to confusion and perhaps additional burdens. Formally proposed EPA revisions to existing CAA programs may impose further burdens if they are adopted. These burdens impact three activities that increase U.S. generating capacity: (1) the construction of new units; (2) efficiency and availability improvements at existing units; and (3) the repowering or reactivation of existing units.

New Construction

The CAA provides two main programs to control emissions from new coal-fired sources: New Source Performance Standards ("NSPS") and New Source Review ("NSR"). Both programs are intended to require the adoption of controls at the time it is most economical to do so – when a new unit is designed and built.

A utility wishing to construct a new coal-fired generating station must comply with NSPS. NSPS require new sources to meet numerical emissions limitations based on the best technology that EPA determines has been "adequately demonstrated." EPA revises these standards periodically to reflect advances in emissions control technology.

In areas that are in attainment with National Ambient Air Quality Standards ("NAAQS"), a new major source also must comply with prevention of significant deterioration ("PSD") requirements. PSD rules require new sources to adopt the "best available control technology" ("BACT") and to undergo extensive pre-construction permitting. This includes air quality modeling and up to one year of air quality monitoring to determine the impact of the new source on air quality. EPA or state permitting authorities determine what type of control constitutes BACT on a case-by-case basis. BACT may require control beyond NSPS for that source category, but may not be less stringent than applicable NSPS.

A company that constructs a new major source near a "Class I" attainment area must satisfy additional requirements. Class I areas include most national parks, and federal land managers ("FLMs") are charged with protecting air quality in these areas. PSD rules require that FLMs receive copies of PSD permit applications that may impact air quality in Class I areas. In cases where the new source will not contribute to emissions increases beyond allowable levels for the attainment area (*i.e.,* beyond the PSD "increment" for that area), the FLM may still object to issuance of the permit based on a finding that construction of the source will adversely impact "air quality related values" ("AQRVs") (including visibility) for that area. The FLM bears the burden of making that adverse impact demonstration. If the state concurs with the determination, then a permit will not be issued. In cases where the new source would contribute to emissions beyond the PSD increment, the company must satisfy both the FLM and the permitting authority that the unit will not adversely impact any AQRVs, before the permit may be issued.

A company that constructs a new major source in a nonattainment area must satisfy NSR requirements similar to, but more stringent than, PSD requirements. Instead of adopting BACT, the source must adopt control as needed to meet the Lowest Achievable Emission Rate ("LAER") for that source category. LAER is based on the most stringent emissions limitation found in the state implementation plan ("SIP") of any state, or the most stringent emission limitation achieved in practice in the source category, whichever is more stringent. A new major source in a

nonattainment area also must demonstrate that any new emissions caused by the source will be offset by greater emissions reductions elsewhere.

In July 1996, EPA proposed changes to these new source programs that would increase the burdens on the construction of new generating stations. EPA's proposal would give FLMs the authority to require companies to perform AQRV analyses even where their new units would not cause exceedence of the PSD increment. A company's PSD application would not be considered complete until it had completed these analyses. EPA's proposal also would transfer authority from EPA to FLMs to define AQRVs and determine what qualifies as an "adverse impact" on those values. These changes, as a whole, would increase the ability of FLMs to control the timing and eventual issuance of PSD permits. EPA also would require state and federal permitting authorities to adopt a "top down" method for determining BACT. Under this method, a PSD applicant must adopt as BACT the most stringent control available for a similar source or source category, unless it can demonstrate that such level of control is technically or economically infeasible. The effect of the policy is to make BACT more similar to LAER in the stringency of control required. The proposed rule is now under review by the Bush EPA.

Following another recent EPA determination, new sources may be required to meet technology-based emission limitations for mercury and other air toxics. On December 20, 2000, EPA indicated that it would regulate emissions of mercury and possibly other air toxics from coal- and oil-fired utilities under the CAA's maximum achievable control technology ("MACT") program. Depending on the basis for the determination, state and federal permitting authorities may be required to impose unit-specific MACT limits on new coal- and oil-fired units until a categorical federal standard is promulgated in 2004. As its name implies, MACT would require units to meet a numerical emissions limitation consistent with the use of the maximum control technology achievable for regulated pollutants.

New source permitting is a lengthy process. The permit must be issued within one year of the filing of a "complete" application. Developing a "complete" application, however, can take another year or longer, as a source negotiates with the permitting authority, FLM, and others regarding modeling, monitoring, control technology, AQRVs, and other issues. If the proposed revisions to the NSR rules are finalized and if case-by-case MACT determinations are required, this permitting process for new sources will take even longer. Even without these proposed revisions, it will be important to consider how this permitting process can be streamlined and expedited.

Efficiency/Availability Improvements at Existing Units

Utilities have many opportunities to increase electrical output at existing units without increasing fuel burn by improving efficiency or reducing forced outages through component replacement and proper maintenance. In some cases, utilities do so as a reaction to unexpected component failures (reactive replacement). In others, utilities replace worn or aging components that are expected to fail in the future or whose performance is deteriorating (predictive replacement). In some cases, utilities replace components because more advanced designs are available and would improve operating characteristics at the unit. Such component replacement can restore a unit's original design efficiency or, in some cases, improve efficiency beyond original design.

Babcock & Wilcox ("B&W"), industry experts on the construction, operation, and maintenance of coal-fired boilers, identify a number of components that electric generating stations typically replace or upgrade during their service lives to maintain or improve operations. These include

economizers, reheaters, superheaters, furnace walls, burner headers and throats, and other assorted miscellaneous tubing. In their book Steam, the B&W authors identify predictable ages for the failure of these components and offer a variety of upgrade options to be incorporated as replacement parts. Other components that utilities frequently replace or upgrade include fans, turbine blades and rotors, feed pumps, and waterwalls.

NSR rules apply to "modifications" of existing facilities that result in new, unaccounted for pollution. For the first 20 years of these programs, EPA identified only a handful of "modifications." In 1999, however, EPA sued several major utility companies for past availability and efficiency improvement projects like those described above, characterizing them as modifications subject to NSPS and NSR. EPA has further indicated that it will treat innovative component upgrades that increase efficiency or reliability without increasing a unit's pollution-producing capacity as modifications as well. EPA's current approach to these projects strongly discourages utilities from undertaking them, due to the significant permitting delay and expense involved, along with the retrofit of expensive emission controls that are intended for new facilities. This is the greatest current barrier to increased efficiency at existing units.

NSR rules define a modification as a physical change or change in the method of operation that results in a significant increase in annual emissions of a regulated pollutant. However, the rules exclude activities associated with normal source operation from the definition of a physical or operational change, including both "routine maintenance, repair, and replacement" and increases in the production rate or hours of operation.

For more than a decade following the establishment of these programs, EPA made very few determinations that projects triggered NSR as "modifications." These determinations involved sources that: (1) added new capacity beyond original construction, for example by adding an entirely new generating unit; or (2) reactivated a long-shutdown unit.

In 1988, EPA concluded that a collection of component replacements intended to extend the lives of five Wisconsin Electric Power ("WEPCo") generating units that had been formally derated and were at the end of their useful lives triggered NSR. Pointing to the project's "massive scope," unusually high cost ($80 million spent on five 80-MW units) and "unprecedented" nature, EPA concluded that the project was not "routine," and calculated an emissions increase for purposes of NSR.

Following the WEPCo decision, utility companies and the Department of Energy asked EPA to clarify the impact of its ruling for common component replacement projects in the industry. Through a series of communications with Congress and the General Accounting Office, EPA assured utilities that "WEPCo's life extension project is not typical of the majority of utility life extension projects, and concerns that the agency will broadly apply the ruling it applied to WEPCo's project are unfounded."

In 1992, EPA issued regulations that confirm the historical meaning of the modification rule and provide special guidance on the application of the rule to electric utilities. Under the 1980 rules, the method used to determine an emissions increase for NSR purposes depends on whether a unit is deemed to have "begun normal operations." The preamble to the 1992 rule states that units are deemed not to have begun normal operations only when they are "reconstructed" or replaced with an entirely new generating unit. Units deemed not to have begun normal operations must measure an emissions increase by comparing pre-change actual emissions to *potential* emissions after a change. Since few facilities operate at full capacity around the clock before a change, this test – if applied to existing sources -- nearly always shows an apparent emissions increase (even where

emissions in fact decline after the change). Sources that have begun normal operations may compare actual emissions before the change to a projection of actual emissions after it. For utilities, the 1992 rule allows a comparison of past actual to "future representative actual emissions," a term defined to allow elimination of projected increases in utilization due to demand growth and other independent factors (provided that post-change utilization confirms the projections). Other units make a more generic comparison of pre- and post-project emissions holding production rates and hours of operation constant.

In the decade following the WEPCo decision, utilities continued to undertake the replacements described above without incident. In November 1999, however, EPA commenced a major PSD enforcement initiative against seven utility companies and the Tennessee Valley Authority alleging violations of PSD provisions. In complaints and notices of violation ("NOVs"), EPA alleged that replacements of deteriorated components undertaken at these units over the past 20 years were non-routine and triggered emissions increases under NSR rules. The complaints and NOVs target component replacements common in the industry, including economizers, superheaters, reheaters, air heaters, feedwater pumps, burners, turbine blades and rotors, furnace and water wall sections, and other components. EPA has since expanded the enforcement initiative to cover more than 20 companies, with plans to add more.

EPA's claim that these projects are now non-routine has left utilities highly uncertain about the coverage of the modification rule. In particular, EPA now suggests that it has discretion to classify projects as non-routine for several new reasons, including the fact that the replacement restores availability, improves efficiency, or involves a major component. At the same time, EPA has raised the stakes for a finding that a project is non-routine by assuming an emissions increase from all non-routine projects. Specifically, in contrast to the NSR rule, EPA now asserts that any non-routine change makes a unit into one that has not "begun normal operations" – necessitating use of an "actual to potential" emissions increase test that the unit is sure to fail. This is true even where such units have an extensive past operating history that would allow reliable predictions of future actual emissions.

A utility considering projects similar to those targeted in the complaints and NOVs must confront the fact that EPA has claimed broad discretion to classify availability and efficiency improvement projects as non-routine modifications subject to NSR. NSR requires the retrofit of BACT technology, which can cost hundreds of millions of dollars, and can delay projects by several years while permits are obtained and/or controls installed. Accordingly, EPA's actions strongly discourage utilities from undertaking projects that improve efficiency, and thereby increase generation without any increase in pollution.

B&W's Steam suggests the scope of projects blocked by EPA's current approach to modification. In order to reach a standard 55 to 65 year operating life, B&W estimates that a typical utility will replace its superheaters and burners at least twice, its reheaters at least once or twice, the economizer and lower furnace at least once, and all other tubing at least three times. Turbine blades are replaced more frequently still. Industry-wide, this means thousands of major component replacements may be prevented or delayed by EPA's approach, as well as other categories of projects EPA has not yet addressed but may find non-routine under its new discretion.

Moreover, EPA has extended its approach to innovative component upgrades that improve unit efficiency and other operating characteristics. In a letter dated May 23, 2000, EPA concluded that a plan by the Detroit Edison Company to replace worn turbine blades with new, improved blades was non-routine. Detroit Edison proposed to replace existing blading with a new, more durable

blading configuration that would increase the efficiency of two turbines by 4.5% each. This would allow these units each to produce 70 additional megawatts of power with no increase in fuel consumption, or to continue producing at past energy levels while reducing fuel consumption by 112,635 tons of coal per year, SO_2 emissions by 1,826 tons per year ("tpy"), and NO_x emissions by 1,402 tpy. This would also allow an incidental 259,111 tpy reduction in CO_2 emissions – a compound that EPA currently lacks authority to control. The company estimated that widespread adoption of the upgrade at compatible units would allow CO_2 reductions of approximately 81 million tpy, with correspondingly large reductions in NO_x and SO_2. EPA based its finding of non-routineness in part on the fact that the project made use of new, upgraded component designs. EPA reached a similar conclusion in 1998, finding that a proposed blade replacement project at a Sunflower Corporation power plant could not be routine because it involved redesigned/ upgrad[ed]" components. Accordingly, utilities contemplating innovative upgrades of turbine and other components to improve efficiency face a known risk that EPA will classify them as non-routine modifications based on their use of advanced technology. Although the exact numbers of innovative projects blocked by EPA's approach is difficult to quantify, the example of Detroit Edison suggests that the losses in generation and pollution reduction from these efficiency gains is substantial.

In sum, EPA's new approach to its NSR rules presents a significant regulatory barrier to projects at existing sources that would otherwise be undertaken to improve availability and efficiency. This barrier can be expected not only to prevent significant gains in generating capacity at existing units, but also to actively reduce availability of these units by preventing needed maintenance. As a related matter, this barrier also can be expected to inhibit development of more efficient generating technologies, reducing the amount of energy that may be produced from existing units, and to encourage prolonged reliance on units operating at lower efficiencies.

Repowering and Reactivation

Replacing a coal-fired boiler with a more efficient generating technology, such as fluidized bed combustion, or an integrated gasification combined cycle, or state-of-the-art pulverized coal technology, can increase generation at an existing facility. This process is commonly known as "repowering." Title IV of the CAA grants special treatment to utilities that meet the acid rain requirements of that title through repowering. A project that qualifies as "repowering" for Title IV purposes also gains exemption from NSPS requirements if the project does not increase the unit's maximum achievable hourly emissions. Such projects almost certainly require PSD review, but are granted expedited review under the Act. EPA has yet to implement these expedited review procedures. Additional uncertainties for permitting these facilities are created by EPA's proposal to "reform" the new source permitting process discussed above.

Reactivation of shutdown existing units presents another means for utility companies to increase generation. A source that has been shutdown for an extended period may be subject to NSPS and/or NSR when it is reactivated. Early determinations on this topic are often unclear or inconsistent as to whether the reactivated unit is subject to NSPS or NSR because it is deemed to be a new unit, or because it is deemed to be an existing unit that has undergone a "modification." In its most recent determination on the subject, EPA has suggested that a unit could be subject to NSPS/NSR for either reason – making for a stricter, two-part standard. Clarification of EPA's reactivation policy, and streamlining of NSR requirements for reactivated facilities, would contribute capacity needed to respond to demand peaks.

Solutions

EPA's proposed rule on NSR would impose significant additional burdens for new sources if it is finalized in its current form. EPA's recent listing of coal- and oil-fired electric utility steam generating units as major sources of hazardous air pollutants could require additional, extended pre-construction review for new and reconstructed facilities. EPA's recent reinterpretation of the modification rule with respect to routine repair and replacement, calculating emissions increases, and source reactivation imposes additional burdens that discourage projects that increase unit availability and efficiency or reactivate shutdown units, including cases where shutdown was never intended to be permanent. EPA should return to its historic interpretation and application of these rules.

APPENDIX A
Description of The National Coal Council

Recognizing the valuable contribution of the industry advice provided over the years to the Executive Branch by the National Petroleum Council and the extremely critical importance of the role of coal to America and the world's energy mix for the future, the idea of a similar advisory group for the coal industry was put forward in 1984 by the White House Conference on Coal. The opportunity for the coal industry to have an objective window into the Executive Branch drew overwhelming support.

In the fall of 1984, The National Coal Council was chartered; and in April 1985, the Council became fully operational. This action was based on the conviction that such an industry advisory council could make a vital contribution to America's energy security by providing information that could help shape policies relative to the use of coal in an environmentally sound manner which, in turn, could lead to decreased dependence on other, less abundant, more costly, and less secure sources of energy.

The National Coal Council is chartered by the Secretary of Energy under the Federal Advisory Committee Act. The purpose of the Council is solely to advise, inform, and make recommendations to the Secretary of Energy with respect to any matter relating to coal or the coal industry about which the Secretary may request its expertise.

Members of The National Coal Council are appointed by the Secretary of Energy ad represent all segments of coal interests and all geographical regions. The National Coal Council is headed by a Chairman and a Vice Chairman who are elected by the Council.

The Council is supported entirely by voluntary contributions from its members. It receives no funds whatsoever from he Federal government. In reality, by conducting studies at no cost which otherwise might have to be conducted by the Department, it saves money for the government.

The National Coal Council does not engage in any of the usual trade association activities. It specifically does not engage in lobbying efforts. The Council does not represent any one segment of the coal or coal-related industry or the views of any one particular part of the country. It is, instead, to be a broad, objective advisory group whose approach is national in scope.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the requested study. The first major studies undertaken by The National Coal Council at the request of the Secretary of Energy were presented to the Secretary in the summer of 1986, barely one year after the startup of the Council.

APPENDIX B
The National Coal Council – 2001 Membership Roster

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APPENDIX E
Correspondence Between U.S. Department of Energy and the National Coal Council

The Secretary of Energy
Washington, DC 20585

November 13, 2000

Mr. Steven F. Leer
Chairman
The National Coal Council
2000 North 15th Street
Suite 500
Arlington, Virginia 22201

Dear Mr. Leer:

Recent rolling brownouts and power outages in the U.S. have raised electric system reliability as a key issue for the electric power industry. Since coal-fired powerplants generate more than one-half the electricity used in the U.S., greater availability of power from these coal plants could contribute to overall electrical system reliability.

I am requesting that the Council conduct a study on measures, which the Government or Government in partnership with industry can undertake to improve the availability of electricity from coal-fired powerplants. The study should address improving the availability of coal-fired power generation in the following two areas:

1. Improving coal power technologies to produce more power. Obtaining more power from existing and new coal-fired power plants can be facilitated by improving the efficiency, environmental performance, and availability of these plants. This part of the study should be technology oriented and include:

- lower cost pollution control and efficiency improving technologies for retrofit applications at existing power plants to ensure higher levels of operation will not generate additional emissions;
- technologies to achieve near-zero emissions at new power plants;
- the role of Federal investment in physically demonstrating clean coal technologies, as well as advanced models to reduce the uncertainty in technology performance of emerging technologies ("virtual demonstration"); and
- the need for improved capacity planning tools to ensure capacity is built when needed.

2. Reducing regulatory barriers. Streamlining the regulatory and permitting process will allow new plants to come on line more quickly. Key to achieving this goal is ensuring that advanced technologies are available to minimize emissions from the new plants. Reducing regulatory barriers includes:

   - reducing regulatory review and siting and construction permitting lead times for extremely clean power systems,
   - creating regulatory mechanisms to reward greater reliability, and
   - conducting R&D to facilitate a comprehensive approach to addressing environmental issues facing existing coal-fired powerplants.

I understand this proposed study was presented to the full Council at their meeting on November 9, 2000, and it unanimously agreed to move forward on the study pending this formal request. The Department looks forward to receiving the study.

Yours sincerely,

Bill Richardson

Bill Richardson

APPENDIX F
Correspondence From Industry Experts

Neural Network Combustion Optimization Technology

Neural Networks are a software approach to emulating the learning behavior of living neurons within the human brain. Since the 1950's, neural nets have developed into a powerful family of tools and techniques which offer adaptive (learning capable) technology with proven pattern recognition ability, making neural nets suitable for complex tasks with multi-variable interactions. This technology has proven to be an excellent application for the combustion optimization of coal-fired boilers within the utility power generation industry.

Neural network based software packages are now available to optimize power plant operations that improve heat rate performance and reduce NO_x and other harmful emissions. NO_x reduction and heat rate improvements were once believed to be contradictory goals. Heat rate and NO_x reductions are possible by optimizing the boiler combustion process. The basis for boiler combustion optimization lies in identifying the relationship of important fuel/air parameters. Values for these parameters are computed and transmitted to the boiler control system as modified setpoints that will provide improvements for heat rate, NO_x and combustibles (CO and LOI). The implementation period to install the neural network combustion optimization is estimated at 5-6 months. The benefits, which have been achieved through the use of the neural network combustion optimization technology, include:

- NOx Reductions of 10-60% (Typically 25-30%)
- Heat Rate Improvements up to 5% (Typically 0.5-1%), resulting in reduced coal consumption for equivalent MW and corresponding SO_2 and CO_2 reductions
- Reduction in Loss on Ignition
- Cost Avoidance for Capital Investments involving Plant Retrofits
- Reduced operational costs in conjunction with SCR and SNCR installations
- Reduction in Equipment Failures and Unplanned Outages
- Automated and Continuous Optimization of Multiple Plant variables

The EPA has established stringent standards for the emission rates of various pollutants. Neural network technology provides for a least cost option to reduce NOx emissions. The table below provides some of the capital installation costs developed by EPA for various NOx reduction technologies. Combustion optimization utilizing neural net technology is the least cost option for NOx cost per ton reduction and NOx boiler unit system installation costs. Another advantage of the technology is that there are no variable operating costs, such as ammonia, urea, or natural gas. In fact, neural net technology installed in combination with other NOx reduction options would provide value by reducing the operating costs of the other technologies.

Technology	$/Ton Reduction Cost	$/Boiler Unit Installation (500MW)
NN Combustion Optimization	$50-$250	$250,000-$750,000
Low NOx Burner	$250-$750	$7.5 - $15 million
Selective Non-Catalytic Reduction	$850-$1,200	$5.5 - $7 million
Selective Catalytic Reduction	$1,200-$2,300	$20 - $40 million
Gas Reburn	>$2,000	$5 - $7.5 million

The table below provides some of the financial and operating benefits which could be obtained nationally if neural network combustion was utilized on investor owned utility boilers which are sized at 100 MW or greater. There were a total of 1,207 utility boilers in service in 1999; 813 coal, 307 gas; and 87 oil-fired units. The data was obtained from the Utility Data Institute. The table highlights benefits in three areas: Fuel Efficiency Savings, Increased MW Capacity, and Environmental Emissions Reductions.

Fuel Efficiency savings are developed from the heat rate improvements achieved by the technology. There was over 908 million tons of coal burned in 1999 at an average delivered cost of $24.72/ton. If heat rate improvements were 0.5% average over all the coal fired units, over 4.5 million tons of coal would be saved

for an equivalent number of MWh. This would amount to a $112 million saving in the utility operations. The table also delineates the benefits associated with gas and oil fired units.

Increase MW Capacity can also be achieved through use of the technology. Improved combustion efficiency presents opportunities to avoid unit derate which may be caused by fan or temperature limitations. In 1998, an estimated 2.1 billion MWh were generated. If capacity increases of 0.5% were attained, almost 10.8 million MWh would be available for consumption. At an estimated production cost of $20/MW, utilities would increase their revenues by over $215 million dollars.

The Environmental Emissions Reductions provide a double benefit in terms of the emission reductions achieved in meeting compliance with EPA's Clean Air Act Amendments, and the value of the tonnage of emissions reduced through the cap and trade programs which the utilities must comply with.

The NOx program is in its infancy, and current involves utilities in the Northeast Ozone Transport Region, but will expand over the next few years to include 22 states east of the Mississippi River. Values have fluctuated significantly over the last couple years ($500-$7,000/ton), but provide value to the utilities if emission reductions are made. A 20% NOx reduction would reduce emissions by 1.4 million tons, and utilizing a conservative estimate of $1,000/ton in the cap and trade program, would result in increased revenues to utilities of $1.4 billion annually. The SO_2 and CO_2 reductions are based on heat rate improvements achieved. The SO_2 program has already been implemented, and it is anticipated that some form of CO_2 trading may occur, but is almost a certainty that reductions will be necessary based on the decisions being made at Kyoto.

FUEL EFFICIENCY SAVINGS				
Number of Units (>100MW)	1,207			
		Annual Savings Range		
	1999 Data Totals	0.25%	0.5%	1%
Coal Burned (Tons)	908,232,000	2,270,580	4,541,160	9,082,320
Ave. Coal Cost/Ton	$ 24.72	$ 56,128,738	$ 112,257,475	$ 224,514,950
Gas Burned (MCF)	2,809,455,000	7,023,638	14,047,275	28,094,550
Ave. Gas Cost/MCF	$ 2.62	$ 18,401,930	$ 36,803,861	$ 73,607,721
Oil Burned (BBL)	131,407,000	328,518	657,035	1,314,070
Oil Gas Cost/BBL	$ 16.03	$ 5,266,136	$ 10,532,271	$ 21,064,542
INCREASED MW CAPACITY				
		Annual Savings Range		
	1998 Data Totals	0.25%	0.5%	1%
MWh Generated	2,158,105,000	5,395,263	10,790,525	21,581,050
Average Cost/MWh	$ 20.00	$ 107,905,250	$ 215,810,500	$ 431,621,000
ENVIRONMENTAL EMISSIONS REDUCTIONS				
		Annual Savings Range		
	1999 Data Totals	10%	20%	30%
NOx Emissions (Tons)	7,051,000	705,100	1,410,200	2,115,300
NOx Emissions Cost/Ton	$ 1,000	$ 705,100,000	$ 1,410,200,000	$ 2,115,300,000
		0.25%	0.5%	1%
SO2 Emissions (Tons)	11,968,000	29,920	59,840	119,680
SO2 Emissions Cost/Ton	$ 125	$ 3,740,000	$ 7,480,000	$ 14,960,000
CO2 Emissions (Tons)	2,191,576,000	5,478,940	10,957,880	21,915,760
CO2 Emissions Cost/Ton	$ 1.00	$ 5,478,940	$ 10,957,880	$ 21,915,760

There are a number of proactive utilities that have employed neural net technology, primarily for environmental reasons. However, heat rate can be the major benefit from the technology. The utility industry is working in an unleveled playing field regarding environmental emission reductions for Phase III of the Clean Air Act, and the inconsistencies in the states deregulation implementation requirements. Regardless of these facts, neural net combustion optimization technology will provide benefits to the operation of the utility industry.

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CQ Inc.

January 2, 2001

Mr. Steven Leer
President
National Coal Council
PO Box 17370
Arlington, VA 22216

SUBJECT: Increasing Output from Coal-Fired Power Plants

Dear Mr. Leer:

The latest issue of *Mining Engineering* reports that the Secretary of Energy has asked the Council to investigate alternatives for increasing the availability and capacity of coal-fired power plants. I hope the scope of your investigation will include coal cleaning and upgrading technologies.

EPRI and others have reported significant increases in power plant availability and net plant output resulting from the use of higher-quality coal fuels. For example, the Keystone Generating Station achieved an increase in availability of 6 percentage points from 63.8 to 70.4 when it started using clean coal from its traditional sources that previously supplied run-of-mine coal. Moreover, Keystone also experienced an increase in net plant output of 49 megawatts when clean coal was substituted for the raw coal for which the plant was designed. AEP, TVA, and others have also reported significant power plant benefits from the use of higher-quality coals.

Please consider the following:

- Drying subbituminous coal from the Powder River Basin improves the heat rate of power plants using PRB coal and reduces auxiliary power consumption.

- Substituting bituminous coals for subbituminous coals increases net generating capacity of power plants.

- By purchasing higher-quality coal, presumably clean or "washed", (1) increases availability, (2) reduces auxiliary power consumption and derating, and (3) reduces emissions.

In the 1990s when reserve margins were adequate and electricity prices were low, coal buyers focused their attention on obtaining the lowest cost fuel. This approach resulted in increased use of run-of-mine coals that were cheap even though they resulted in availability losses and derates in some cases. As Secretary Richardson suggests, priorities must change to meet today's marketplace. The fastest and most economical means of addressing those needs is to use higher-quality ("higher-octane") coal. This action will not solve all of our current energy issues, but it will buy some time to design and implement appropriate equipment retrofits or replacements to further improve availability and generating capacity.

I would be happy to provide additional information to your study group, upon request.

Sincerely,

Clark D. Harrison

Clark D. Harrison
President

CDH/baf

cc: William B. Richardson, Secretary of Energy
Rita Bajura, U.S. DOE
Lowell Miller, U.S. DOE

Please Note: CQ Inc. was formed in 1989 as a wholly-owned subsidiary of EPRI to spin off EPRI's Coal Quality Development Center and provide research and engineering services to the energy industry. In 1994, CQ Inc. employees purchased majority ownership in the company from EPRI, and in 1998, we became 100% employee-owned. CQ Inc. and its affiliates currently employ 98 engineers, scientists, managers, and administrative and operating personnel, and we operate five fuel production facilities. More information is available on our website www.cq-inc.com.

Cass County Electric Cooperative
A Touchstone Energy® Partner

March 30, 2001

Honorable Vice President Dick Cheney
The White House
1600 Pennsylvania Avenue
Washington D.C. 20500

Mr. Andrew R. Wheeler
United States Senate Committee on Environment and Public Works
415 Hart Senate Office Building
Washington, D.C. 20510-6175

Gentlemen:

With all due respect, I would like to share a suggestion for a National Energy Policy consideration from two views, first, as a concerned citizen and secondly, from a professional utility managers observation. As a citizen, I read and listen to the media and elected officials talk about energy issues and I must confess that am confused at best, because when I think of the technology advancements made over the past century, I conclude that this should not be happening. In fact, I just read something tagged with the following reference, "should the 21st Century be called the re-occurrence of the dark ages?"

I was recently recognized by the North Dakota State University Alumni Association and in the process was honored to be able to share a presentation on an Alumnus' Perspective of the New Economy Initiative in North Dakota. I am proud to be one of 31 people from across the state to be selected to provide leadership for the challenging task of evaluating what our future holds. So, in making this presentation to students and faculty at this Land Grant University, I referenced a book that I have found to be one of the best comparisons of commitment and dedication to dealing with things thought to be impossible. The book is entitled, "Nothing Like It In the World" written by Stephen Ambrose and it tells the story of the building of the transcontinental railroad from coast to coast. This late nineteenth century task was considered to be impossible, yet as I read the story it showed me Lincoln's vision, the courage of surveyors, and best of all, the *prevailing determination to succeed* by people from all around the world. My point is, that as I ponder all the great past accomplishments of our Nation (building the railroad, the invention of the light bulb, and the development of the electric utility industry, to name a few), it is truly an insult to our society to think of what is capturing the news today on energy issues compared to the commitment leaders and workers displayed during those earlier difficult times.

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As a professional in the electric utility industry, I often find myself attempting to explain the current energy situation and find that what usually ends up being the benchmark of fault, is the lack of an energy policy that is taken seriously by citizens and government. Therefore, I would like to use two specific examples of history that cause me to believe that what I am going to recommend should be given very high consideration in determining energy policy. The first reference is to the oil embargo of 1972 and a local situation that started a program called Dual Energy Heating (the alternating use of two sources of energy for heating). As I explain this, please make note that unbeknownst to us at the time, Hydro Quebec was also experimenting with a very similar concept and I will reference that in my closing remarks.

> In September 1972, the West Acres Shopping Center opened in southwest Fargo and as grand as the event was, a problem was about to happen that no one had considered. The Shopping Center's heating system was designed to use oil and natural gas with a 50% allocation coming from each source, but as a result of the oil embargo, the local gas supplier was forced to stop all "interruptible" delivery to the Center. Of course the Center's owner quickly asked the oil supplier to solve the problem by purchasing heating oil from Minneapolis-St. Paul and although a semi-load of fuel was dispatched, the Energy Office of Minnesota stopped the truck and would not let it leave the state. Well, as they say, the rest is history! Cass County Electric worked with the Center to install electric boilers in January 1974 and the combination of "coal-fired" electricity and the existing oil boilers have worked flawlessly ever since.
>
> In 1983 and '85, Dual Energy Heating Symposiums were held in Toronto, Canada and Fargo, North Dakota with speakers and examples of applications shown from throughout the world. I would like to bring attention to an observation made by our then Secretary of Interior, Don Hodel, while addressing this conference in Fargo. After learning of the experiences and testimonies such as the West Acres Shopping Center, Mr. Hodel said, "if only I would have known how this system works and what it can do, it should be a part of our National Energy Policy."

We are using this same program today 18 years later. ***The issue is that no one has recognized how significantly this program can benefit our current energy situation.*** Hydro Quebec reports 115,000 homes currently using the program and displacing equivalent oil and gas resources everyday; and from within our own generation and transmission system, it is estimated that this program has displaced some 350 million gallons of oil over the last twenty-five years. It is our opinion that coal-fired electric energy can play a very critical role in our nation's overall energy plan … the key is not being dependent on an either/or selection of energy, but a meaningful choice of Dual Energy. * This choice has solved many problems for our member-owners in the Midwest.

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* Check out: Yahoo.com; Search under: dual energy heating

I am attaching some support material from the U.S. and Canada that will demonstrate what we are talking about, and then would boldly suggest that the nation's Energy Task Force explore what this grass roots effort can mean for our entire country. I will be in Washington, D.C. from April 28th through May 2nd and would welcome the opportunity to visit with anyone who wants to learn more about Dual Energy Heating.

Sincerely,

Michael D. Gustafson
President & CEO

CC: North Dakota Senator Kent Conrad
North Dakota Senator Byron Dorgan
Scott Handy, Chief Operating Officer – Cass County Electric
Claire Vigesaa, VP of Development & Energy Services – Cass County Electric
Bill Bertram, Board Chairman – Cass County Electric

Attachments

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March 16, 2001

Ms. Georgia R. Nelson
President
Midwest Generation, EME, LLC
440 South LaSalle Street, Suite 3500
Chicago, IL 60605

I enjoyed your comments from the panel at the Clear Water Coal Utilization Conference
Regards
Robert

Subject: Information for the Coal Policy Committee Study Work Group: R.E. The Proposed Cyclone / Clean Combustion System™ Retrofit Demonstration

Dear ~~Ms. Nelson~~: Robert

We wish forward information that may be of interest to your **Study Work Group** of the **Coal Policy Committee** for the **National Coal Council** on an advanced combustion technology for SO_2 and NO_x emissions control that promises to increase US electricity availability and reliability by an appropriate use of the US coal reserves.

This technology is called The Clean Combustion System™ (CCS). I have enclosed several copies of a recent paper titled "Proposed Dominant Design Basis for Needed Advancement of Coal-Fired Generation" and our CCS brochure for your information.

The CCS is a proven combustion process that uniquely **prevents** the formation of NO_x and SO_2 right within our initial combustion step. The technology is significantly different from the better-recognized pre- and post- combustion processes for emissions control.

With relevant experience from an earlier field demonstration in Canada (at three tons of coal per hour – 50mmBtu/hr), we are proposing to the Department of Energy's Power Plant Improvement Initiative (due April 19), a $12.6 million, 24-month demonstration program to re-power a 33MW Cyclone boiler with the CCS for very low NO_x / SO_2 emissions when firing Illinois #6 coal.

Southern Illinois Power Cooperative, in Marion, Illinois has offered to host the CCS demonstration at their Marion Station, and the State of Illinois Department of Commerce and Community Affairs have offered a letter of support (with funding of up to 20% of the project). With an approval for funding, this demonstration will show that a simple, low-cost combustion modification can provide Utility coal-fired boilers the required ultimate control of the two heavily regulated pollutants from coal - NO_x and SO_2.

The CCS has already demonstrated excellent NO_x performance (0.15 lb./mmBtu) in Western and Midwest coal firings, and we believe it can simultaneously meet the most stringent SO_2 targets as well. The CCS fits cyclone, wall-fired and tangential boiler designs and is a fully qualified re-powering technology as per the 1990 Clean Air Act Amendments. With a full-fledged utility demonstration soon accomplished as foreseen

above, the CCS will have profound implications for the coal-fired power generation industry.

We welcome any questions your **Study Work Group** may have. Thank you for your consideration and your generous giving of your time.

Sincerely,

Phenix Limited, LLC
Keith Moore
President

Cc.: Mr. Robert A. Beck, Executive Director, National Coal Council
Mr. J. Knotts – CFO, Phenix Limited, LLC
Encls. CCS Brochure, and paper

PROPOSED DOMINANT DESIGN BASIS
FOR NEEDED ADVANCEMENT OF COAL-FIRED ELECTRIC POWER GENERATION

By
Keith Moore – President, Phenix Limited, LLC
William Ellison P.E., Director, Ellison Consultants
For Presentation at the 26th International Technical Conference on
COAL UTILIZATION & FUEL SYSTEMS
March 5 to 8, 2001 at Sheraton Sand Key Hotel, Clearwater Beach, FL, USA

ABSTRACT

Newly proposed US legislation and DOE initiatives advance a set of criteria pointing to a new dominant design for coal-fired plants. Such a concept, called the Clean Combustion System™, has evolved from fundamental combustion modeling with strong capability to control both SO_2 and NO_x emissions within the coal combustion step. Research and field development programs have affirmed that this process meets the most stringent US environmental emissions rules. This potentially new dominant design technology is proposed for construction of new plants and the retrofit of existing coal-fired power plants.

INTRODUCTION

Based on a concept known as **"dominant design,"** there is a *standard* – de facto if not de jure – observed by decision makers within any given industry. One example, known to most, is the QWERTY keyboard – which refers to the sequence of the position of keys for individual letters of the alphabet as found on the keyboard of every computer built; this physical arrangement was a practical engineering means to slow the typist so as to deal with the limitations in performance of the mechanisms of early typewriters: if someone were to type too fast, the keys would jam together.

Examples of dominant designs are found everywhere, some perhaps being in vogue for only a temporary period but nevertheless, central to the development of a new industry. What happened to the "dial" phone? "Piston engine" aircraft? By the way, can you find a "typewriter" in use anymore?

During their reign, dominant designs typically have very intrenched supporters. After all, usually there are large intellectual and physical infrastructures involved. An emerging, improved technology is viewed as more complex – initially perhaps – and is significantly different and, perhaps, not readily understood. But sometimes there are new goals or needs that, for one reason or another, become so compelling that those who would hang on to the old practices ultimately languish in deep trouble. Think of the common use of carburetors, a dominant design that served adequately for many decades. However, the auto industry came to face massive government regulations that emphasized improved fuel economy and ambient air quality. As a result and to persevere in the competitive market place the industry looked to innovation and advances in sensors and electronic controls ultimately, with its developmental and engineering talents, it introduced use of fuel injection - a new dominant design.

And so it is now with the coal-fired power boiler industry. Executives, policy makers, and engineers everywhere are vitally concerned for renewal of the industry. Coal-fired energy is the primary source of secure, low-cost electric power in the US and the world, and each participant must address the critical issues of severe environmental regulations, industry deregulation (with its pressure for significant cost reduction), and

the need to improve the reliability and quality of electrical service. These forces are the drivers in a virtual industry-wide search for a distinct renewal pattern, (or paradigm). Innovation, engineering, and technology clearly, must now define a new, appropriate, dominant design for the coal-fired power boiler industry.

We believe there is a valid basis for this dominant design for coal-fired boilers; one that will achieve improved efficiency, economy, and environmental emissions, and that can retrofit existing boiler installations. We herein will first examine anticipated new legislation and concurrent DOE initiatives that may well define the requirements for the needed new approach. A review is thereafter presented of our proposed technical approach and the operational issues and the resulting cost savings for this potential new dominant design for coal-fired power plants.

PROPOSED NATIONAL ELECTRICITY AND ENVIRONMENTAL TECHNOLOGY ACT (NEET)

Legislation is now in progress in Congress to enact a new, comprehensive coal-based technology development and implementation program: to reduce multiple emissions from and improve thermal efficiency of existing coal-based generating plants by stimulating deployment of advanced coal technologies. The NEET Act provides for an *R&D / demonstration program* with *financial incentives* to cushion developmental cost and commercial risk in applying advanced technologies, *tax incentives* for deployment of initial commercial-scale installations of advanced coal-based generating technologies and a *safe-harbor period* from regulations for qualified installations.

NEET sets forth strong, long-term, emission targets and efficiency improvement objectives for contemplated advanced technologies. The following abstract states the "purpose" of the proposed legislation.

(b) PURPOSE- The purpose of this title is to amend the Internal Revenue Code of 1986 and authorize Department of Energy programs to--

(1) Develop and implement an accelerated research and development program for advanced clean coal technologies for use in existing and new coal-based electricity generating facilities,

(2) Provide financial incentives to encourage the retrofit, repowering, or replacement of existing coal-based electricity generating facilities to protect the environment and improve efficiency,

(3) Encourage the early commercial application of advanced clean coal technologies, and

(4) Allow coal, the most abundant domestic energy resource, to help meet the Nation's growing need for clean, reliable, and affordable electricity.

(a) The Secretary shall conduct a program of research, development, demonstration, and commercial application for the purpose of developing economically and environmentally acceptable advanced technologies for utilization at or within current electricity generation facilities using coal as the primary feedstock.

(b) ..... Such plan shall include..... design improvements that will allow such units to provide either--

(A) An overall design efficiency improvement of not less than 5 percentage points on a unit having design main steam throttle conditions of at least 1,800 psi / 1,000°F / 1,000°F,

(B) A design removal for one or more of the following emissions of not less than--

(i) 98 percent removal, annual average, of sulfur dioxide at a capital and operating cost at least 25 percent below commercially available technology;

(ii) 85 percent removal, annual average, of nitrogen oxide without the use of ammonia or urea, or a system for selective catalytic reduction;

(iii) 75 percent, annual average, emission reduction of total mercury excluding any reductions due to use of activated carbon;

(C) 100 percent recycle/utilization options of coal combustion wastes excluding gypsum production for wallboard and coal fly ash and bottom ash use in Portland cement and concrete applications.

DOE - POWER PLANT IMPROVEMENT INITIATIVE (PPII)

The Department of Energy has posted a draft of a PPII solicitation for issue in February 2001. The solicitation offers up to $95 million for 50/50 cost shared demonstrations of advanced coal-based technologies that can broadly improve the U.S. coal-fired electric power generating system.

Eligible projects could include technologies that boost the efficiencies of currently operating power plants – generating more megawatts from the same amount of fuel – or that lower emissions and allow plants to achieve operation in compliance with environmental standards. The program is also open to technologies that improve the economics and overall performance of coal-fired power plants. Proposed technologies must be mature enough to be commercialized within the next few years, and the cost-shared demonstrations must be large enough to show that the technology is viable for commercial use. The first project selections could be made by September 2001.

Since today's coal plants extract only 33 to 35 percent of the useable energy value of the fuel, there may be considerable opportunity to boost the Nation's power supply by increasing the output of these existing plants through technological improvements. In addition, reducing environmental impacts associated with air pollutants, water usage, and solid waste generation could help many older plants comply with stringent environmental standards and prolong their useful life. Technologies proposed in the new program must also advance the performance or cost-competitiveness of new coal-based capacity well beyond today's power plants or those that have been demonstrated to date.

REQUIREMENTS FOR A DOMINANT DESIGN

New dominant design criterion for a coal-fired power plant may be developed from the above precepts. The key issues are to:

1.) Gain control of *multiple pollutants*,
2.) Reduce the amount of *waste products*,
3.) Improve the boiler's *combustion* and system *thermal efficiency*,
4.) Enhance the boiler's *operational reliability*, and
5.) Provide for low cost *retrofitting or repowering* of existing plants.

Additional features include the opportunity to fire a wide range of coals, both Western low-sulfur and Midwest high-sulfur coals, and eliminate the use of hazardous chemicals (ammonia) or other fuels, e.g. natural gas. Moreover, new coal-fired power plants using the technology must reflect significant capital cost reductions.

Roots of the Proposed, New Dominant Design

Note that a new coal-fired dominant design must operate at the highest temperatures practical, (in part to gain high carbon burnout), with low parasitic loads. The most effective multiple pollutant, SO_2 and NO_x control requires the removal of the coal sulfur and prevention of significant formation of nitrogen oxides at the onset of the combustion process. The US Clean Air Act Amendments require SO_2 emissions of less than 1.2 lb./mmBtu for existing coal-fired power plants and > 90 percent SO_2 control for new coal-fired plants. NEET will expect 98% or about 0.1 lb./mmBtu for SO_2 emissions in the case of coal with 3% sulfur. For NO_x, the EPA has set a stringent current requirement of less than

0.15 lb./mmBtu for all power plants during the summer ozone season. NEET will extend this requirement year around.

To meet these requirements, a new dominant design concept evolves as a confluence of know-how and experience implicit in coal gasification and in slag-tap boiler operation integrated such that the coal-ash melts and is fluid at an elevated combustion temperature.

The utility industry has for over thirty years successfully operated slagging combustors such as in the application of Babcock & Wilcox cyclone boilers. The strength of the slag-tap, i.e. wet-bottom, boiler has been its ability to effectively fire the common high-sulfur (~3%S), low-fusion temperature, Midwest bituminous coals. The cyclone processes the coal and completes the combustion at a high rate of heat release. The boiler, itself, then serves primarily as a downstream heat transfer section.

Even as of today, the cyclone boiler design provides the greatest steam generating capacity per ton of steel (used in plant construction) with the smallest facility footprint, a basis for a very low-cost new boiler design. However, the cyclone's high temperature combustion results in high (> 1.0 lb./mmBtu) gross NO_x emissions with essentially all of the coal sulfur reporting as SO_2 and SO_3, as in common dry bottom boiler operation.

Gasification is the conversion of solid and liquid materials (e.g. coal or oil) into a gas whose major components are hydrogen (H_2) and carbon monoxide (CO). Gasification has been employed for over a hundred years with the gas produced being used for various applications such as domestic heating and lighting, ("Town Gas") and chemicals manufacture, e.g. ammonia (NH_3) or methanol.

The first major application of gasification was to convert coal into a fuel-gas for domestic lighting and heating. This application has gradually died out in most places due to the availability of natural gas.

The defining chemical characteristic of gasification is that it entails the partial oxidation of the feed material; in combustion, the feed is fully oxidized, in pyrolysis, the feed undergoes thermal degradation in the limited presence of O_2.

Gasifiers fall into three groups: entrained flow, fluidized bed and moving bed. Entrained flow gasifiers are similar in concept to pulverized fuel firing; fluidized bed gasifiers are exactly analogous to fluidized bed combustors; and moving bed gasifiers bear some resemblance to grate firing.

In an entrained flow gasifier, pulverized fuel flows co-currently with the oxidizing medium. The key characteristic of entrained flow gasifiers are their very high and uniform temperatures (usually more than 2000°F) and the very short residence time of the fuel within the gasifier (< 1 second).

For this reason, solids fed into the gasifier must be very finely divided (pulverized to a standard grind of 200 mesh) and homogeneous, (which in turn means that entrained flow gasifiers are not suitable for feedstock's such as biomass or wastes, which cannot be readily pulverized.) The high temperatures in entrained flow gasifiers mean that the ash in coal melts and is removed as a molten slag.

A proven means to achieve NO_x and SO_2 control involves high temperature coal gasification under very fuel-rich conditions in the presence of finely divided calcium oxides. NO_x cannot form under such conditions and the sulfur can be captured as solid calcium-sulfur compounds. The gasification of the coal fuel, forming a hydrogen and carbon monoxide fuel-gas mixture, constitutes a major simplified adaptation of established gasification technology and provides the basis for a strategic means for deep $deNO_x$ / $deSO_x$ in modified operation of existing conventional coal-fired boilers.

Background and Implementation of Fuel-Rich Combustion

NO_x Control [1]

The early 1980's witnessed NO_x control studies that focused on a greater understanding of the two sources of NO_x in combustion: From 1.) in the case of coal and oil combustion, oxidation of fuel bound nitrogen.) and 2) the thermal oxidation of gaseous nitrogen, i.e. the "Zeldovitch mechanism".

For nitrogen-containing fuels such as coal (which includes about 1% N_2) and oil, the fuel nitrogen is the predominant source of NO_x. However, when the combustion is carried out in an adequately fuel rich or sub-stoichiometric mode, the necessary oxygen to form a substantial amount of NO_x from fuel nitrogen is simply not available. Further, fuel-rich combustion at high temperatures is shown to reduce NO_x formation attributable to gaseous nitrogen.

High NO_x emissions of cyclone boilers made them early candidates for fuel-rich operation serving as an abatement means. However, it was quickly learned that merely air-starving these combustors is not practical, particularly for high sulfur coals, because fuel-rich operation forms very corrosive sulfurous gases (H_2S), and compounds such as iron sulfide, that is liberated from the pyrites in the coal.

This results in aggressive attack of the metal walls of the boiler as molten and gaseous sulfides will eat through a water-cooled tube "like a hot knife cuts through butter". Thus, early / immediate sulfur capture is an essential element in a NO_x control means based on fuel-rich combustion.

SO_2 Control in the Clean Combustion System™ (CCS)

The CCS process offered by **Phenix Limited, LLC**, is such a high temperature, fuel-rich combustion process, air-staged wherein a specified residence-time, temperature and stoichiometry is provided for the initial stages of the combustion process.

Figure 1 shows the simplified CCS schematic including its initial coal gasification and sulfur capture step. The CCS burner, it should be noted, is a simple injection/mixing step that carries out the gasification in a refractory lined section upstream of the boiler. The coal is pulverized to a standard grind and conveyed by air to the CCS combustion chamber (limestone is pulverized separately and added as required to provide needed alkali).

At high temperatures and with limited oxygen available, the CCS gasifies the coal to release all its elements (carbon, sulfur, ash constituents and nitrogen) into the combustion-gas mass. Under these conditions, and in the presence of the calcined limestone, the coal sulfur reacts in the combustor to form calcium sulfide (a non-gaseous compound).

The now known key to achieving high sulfur capture is to ensure that the organic and pyritic forms of sulfur bound in the coal are released to the combustion gases. (Any sulfur not so liberated and immediately captured is later oxidized in the boiler by supplemental combustion air and released as SO_2.) Additionally, these fuel-rich conditions simply prevent NO_x from forming in the slagging combustion step.

At these high temperatures, the coal ash melts and forms a molten glassy slag that tightly binds the captured sulfur. The resulting inert slag mass and sulfur component drains from the burner to water-filled quench tank and ash transport system.

The resulting acid-gas-free, hot combustion gases, largely nitrogen, CO and H_2, then exit to the boiler furnace. Sufficient time is there available for the hot gases to be substantially cooled by the water walls prior to entry of final supplemental overfire air to complete combustion of CO and H_2 at temperatures at which thermal NO_x generation is frozen, thus avoiding formation of any new NO_x.

Figure 2 shows the retrofit concept for a typical pulverized coal (dry bottom) wall-fired boiler embodying the CCS conversion. Necessary modifications (three in all) replace the existing burner wall with a factory fabricated CCS burner section, add new overfire air ports and ducting and thirdly, convert the boiler to "wet bottom" operation with a new slag/ash transport system. The balance-of-plant modifications include the addition of equipment to meter the powdered limestone to the CCS / coal pulverizing system.

In recent years, there has been rising interest in using gasification to generate electricity, and this is now mirrored by the advent of CCS. The principal encouragement for coal gasification has been the development of large, efficient gas turbines.

It was realized, initially, that the gasification of coal, coupled with a gas turbine, could potentially generate power as efficiently as the most modern conventional coal-fired power plant, but with much lower emissions. Gasification act as a "bridge" between conventional fuels such as coal (and fuel oil) and gas turbines.

Gasification of such fuels generates a fuel-gas which, after cleaning, can be used in a gas turbine power plant. Gasification therefore enables the advantages of gas turbine technology to be accessed using any fuel, weather solid or liquid, in an integrated gasification combined cycle plant.

However, ironically, unlike the convenience with which CCS can be retrofitted to existing boilers, there are major barriers to IGCC becoming widely adopted for coal.

- Capital cost approximately 20 to 30 % greater than conventional coal-fired units
- Limited reliability in performance of turbine combustors
- Complexity in integration of its multiple steps as configured for use of a gas turbine driven electric generation
- Cold start-up time in excess of 40 hours
- Unproven load following capability.

Combustion and System Efficiency

Combustion efficiency relates to the conversion of the carbon of the coal to heat and CO_2 and minimizing LOI (loss on ignition). System efficiency describes the ratio of net electrical energy produced from the total available Btu's provided by the fuel, and accounts for the energy losses inherent in the equipment that generates the electricity.

The purpose of a burner is to create the necessary conditions of fuel and air mixing, time and temperature to completely oxidize the coal fuel to H_2O and CO_2. LOI measures the success of the burner's design and its operation over the range of power plant loads.

The Low NO_x burners (LNB), recently mandated by the EPA to reduce NO_x emissions on PC boilers report increased LOI. To achieve NO_x control, LNB's employ techniques to slow the combustion and reduce the peak flame temperatures. The result is an increase in LOI with 5 to 10 percent carbon in the flyash (and in some cases, as high as 20% with the Western low-sulfur coals). The poor combustion may also result in slagging and fouling of the boiler internals, and an overall 3 to 5 percentage point derate in the boiler's steam generation efficiency.

Fluidized bed combustion (FBC), a technology often promoted as an example of multipollutant SO_2 and NO_x control also reports high LOI. FBC's burn coal in a bed of air-fluidized sand and limestone (calcium) at temperatures of 1600 to 1700 °F. These low combustion temperatures are required so the calcium can capture the coal's sulfur as a $CaSO_{3,4}$ compound(s). The high concentration of particulate in the freeboard leads to lower NO_x emissions, and the low temperatures avoids clumping and fusing the coal ash.

However, the FBC's low combustion temperatures result in two significant efficiency penalties; 1.) the low thermal delta T (~1200 °F) reduces thermodynamic efficiency

and 2.) poor carbon burnout (high LOI). FBC's also require high-horsepower fans to pump the fluidizing air and thus have high parasitic operating loads.

As a result, FBC's report a 7 to 10 percentage point "system efficiency" penalty when compared to a pulverized coal fired boiler. For these reasons, FBC's applications focus on the difficult, very low-cost, waste fuels such as coal culm, automobile tires and residual oil/coke.

"NEET" Issues for the Reduction of Solid Waste and Mercury [2]

The CCS directly addresses NEET requirements for solid wastes, as the product is an inert, glassy, grit-waste product similar to the slag from cyclone boilers. Cyclones units can sell nearly all their slag (~$2 /ton or hauled away free of cost) for many industrial uses, such as shot-grit for metal blasting, road grit, and roofing materials. There is also a residual, near-zero-carbon-content, readily marketable, flyash component that is collected by an ESP or baghouse downstream of the boiler.

Even though the quantity of mercury in coal is only about 1 part in a million, NEET looks to address the issue of mercury emissions from all US coal plants, some 72 tons/year per EPA estimates. The amount of mercury in the stack gas stream from coal combustion is very low, usually in the range of 5 to 10 $\mu g/m^3$. Under fuel rich combustion conditions, mercury released from the coal may react with sulfur to form mercuric sulfide (HgS). Subsequently, under excess air conditions, it forms mercuric chloride ($HgCl_2$) that can be removed in downstream flyash collection.

Many attempts at mercury control in actual power plant flue gases have met with limited success and the results are very difficult to measure. Of interest are the reports that the mercury emissions from gasification and from slagging (wet-bottom) operations are only one-third that measured from typical pulverized coal-fired (dry-bottom) operation. This suggests there may be a capture mechanism wherein the mercury is encapsulated in the inert glassy slag product. It may be postulated that the CCS sulfur capture mechanism thereby has potential to provide a significant level of mercury control.

Pending CCS Cyclone Retrofit Demonstration for the DOE - PPII

Phenix Limited, LLC proposes to conduct a 24-month, $12.6 million demonstration of the CCS process on a utility cyclone boiler firing Illinois #6 high-sulfur coal. Figure 3 shows the proposed modifications to the cyclone boiler including the addition of a pulverized coal and limestone/additive feed system. The repowered plant will then be operated for a sufficient period to establish the operability, reliability and availability of the CCS system and demonstrate its commercial merits.

The CCS performance goals are to show a simple, safe, and stable combustion operation and directly address the DOE - PPII with:

1.) *Multiple pollutant* control:

- SO_2 <1.2 lb./mmBtu
- NO_x < 0.15 lb./mmBtu

2.) *Waste product* reduction by generating an inert slag by product for marketing disposal

3.) *Thermal / system efficiency* improvement with +99% carbon burnout's

4.) Enhanced boiler *operation and reliability* with furnace corrosion and ash deposition control, and

5.) Demonstrated low cost *retrofit / repowering* technology for coal-fired plants.

Follow-on technical and performance improvements in the CCS technology are foreseen to further improve its sulfur capture to meet NEET's anticipated aggressive emission goals.

With the demonstration of the CCS, the utility industry will witness a single technical solution to alleviate the adverse impact of

current and future environmental regulations on the State of Illinois and the electric power industry. Ongoing CCS retrofit studies for power plants will develop site-specific requirements of each and confirm an engineering basis for multipollutant control, efficiency and the concepts to retrofit existing power plants.

A *new power boiler design* based on an optimized CCS configuration can provide major capital cost savings for new coal-fired plants. Such a design would provide the largest MW per ton of steel, a small facility footprint, and include requisite emissions control. Thus, the basis for a new dominant design for coal-fired power plant combustion operation will have been established.

Background for the CCS: Rockwell International

The CCS is the latest evolution of early combustion work at Rockwell International in conjunction with fundamental combustion modeling that predicted capability for strong control of SO_2 and NO_x emissions within the combustion step. The concept was extensively tested with private funds in the 1980's at Rockwell's 25 million Btu/h (one t/h coal) pilot scale facility.

The work was proprietary without public disclosure and, consequently, very little has to date been reported to industry. A consortium of utilities guided and supported much of the work. The test program focused on fuel-rich combustion of both low-sulfur Western subbituminous and the high sulfur Midwest bituminous coals. The test results showed good SO_2 control and consistently reported very low NO_x emissions.

TransAlta's LNS-CAP Project [3]

TransAlta, a major Canadian electric utility, thereafter initiated an $12.2 million industrial scale demonstration of the burner on a 50 million Btu/h oil-field steam generator at the ESSO Resources Cold Lake heavy oil recovery site in Alberta, Canada. Called the Low NO_x / SO_x - Coal Applications Pilot (LNS-CAP) Project, the facility fired three ton/h of low sulfur subbituminous coal, consuming approximately 400 tons of coal in all.

The LNS-CAP process combined four major systems corresponding to those of most coal-fired facilities: 1) coal receiving and storage, 2) coal preparation, 3) coal combustion, and 4) solid waste handling.

The burner was mounted vertically and incorporated a 115-degree elbow for entry to the steam generator. The elbow geometry caused most of the slag to report to the combustor walls and drain out the slag tap. A gas burner was used to preheat the burner refractory wall and initiate startup on coal. Once at temperature, the burner operation was smooth and stable over a wide range of turndown. The slag exited the burner through a slag tap into a water quench trough and was conveyed to a dumpster unit for disposal.

The LNS-CAP actual stack outlet SO_2 and NO_x emissions are shown in Figure 4. Sulfur dioxide emissions were typically 0.2 lb./mmBtu. NO_x control demonstrated an emission rate of approximately 0.15 lb./mmBtu. Carbon burnout was also excellent, with an LOI measured in the fly ash (collected downstream in a baghouse) of less than 0.1 percent. No carbon was found in the slag.

CCS CAPITAL AND TOTAL COST ($/TON OF NO_x REDUCTION) IN COMMERCIAL RETROFIT APPLICATION[3]

For the grandfathered coal-fired plants, including wall-fired, and tangentially-fired boiler designs, estimated capital cost for CCS retrofit ranges from a low of $65 /$kW_e$ for large (>500MW_e) boilers to a high of $120 /$kW_e$ for the smaller (100 MW_e) boilers. Site specific issues will affect the retrofit cost of each plant.

It is convenient to compare technologies on a cost-effectiveness basis of $/ton NO_x "abatement" in combustion (CCS) vs. that abated, collectively, by conventional primary

control in conjunction with secondary deNO_x (SCR). The gross NO_x emissions vary widely among boiler types and are nominally:

- Cyclone 1.0 lb. NO_x /mmBtu
- PC wall-fired 0.55 lb. NO_x/mmBtu
- Tangential 0.45 lb. NO_x/mmBtu

Table 1 estimates the $/ton of NO_x reduction for commercial plants comprising the three boiler types, each retrofitted with the CCS.

These costs are markedly less than those for SCR control technology, and yet provide both SO_2 as well as NO_x control.

Table 1. CCS – Capital Cost and Total Cost, ($/Ton NO_x Reduction)
(0.10 lb. NO_x/mmBtu at stack)

Boiler Type (500 MW_e)	Cyclone	PC Wall-Fired	Tangential
Capital Cost	$105/kW	$65/kW	$70/kW
Total Cost	$270/Ton	$380/Ton	$460/Ton

Thus, the attractive economics of slagging combustion foreseen via ongoing commercial development of CCS underlines its strategic significance in the new decade in its use as a high-tech, deep deNO_x / deSO_x retrofit control means. But, more significantly, as a key and potentially dominant technology, the CCS will afford a new "way of life" for practical, economical refurbishment of existing coal-fired boiler assets throughout the world for cost-effective fossil fuel combustion, fully integrated with stringent environmental protection.

References:

1. "Fuel-Rich Combustion – A Low-Cost NO_x Control Means for Coal-Fired Plants"; Moore, K. and W. Ellison, 25th International Technical Conference on Coal Utilization and Fuel Systems, March 6 - 9, 2000
2. IEA Coal Research - Perspectives: "Mercury emissions and effects – the role of coal – Emissions from Coal Utilization" Chapter 3, p 9; August 1995
3. "Demonstration of TransAlta's Low NO_x / SO_x Burner"; Frasier, W.L. and G. Elia, International Joint Power Generation Conference, October 6 - 10, 1991.

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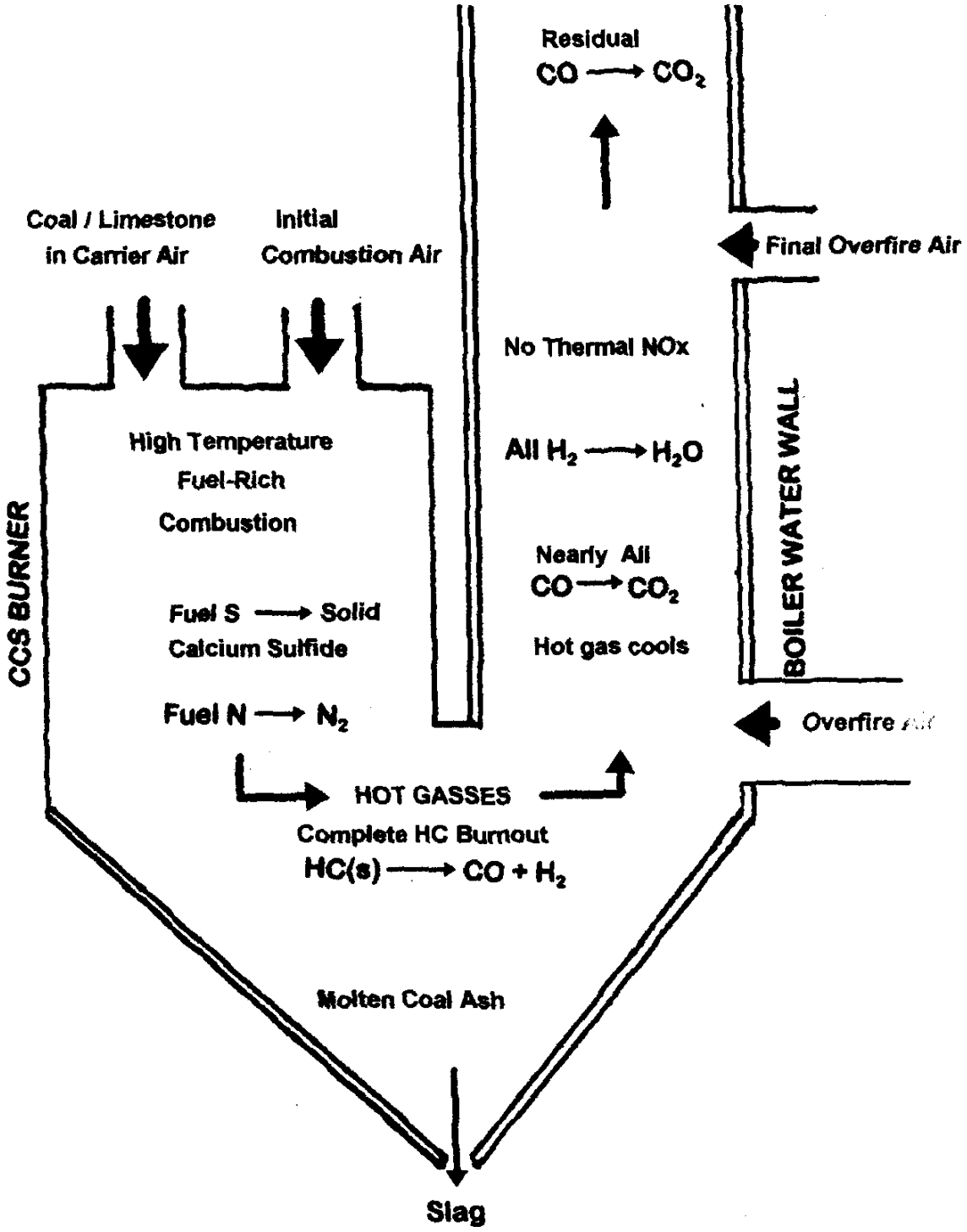

FIGURE 1. Simplified CCS Schematic

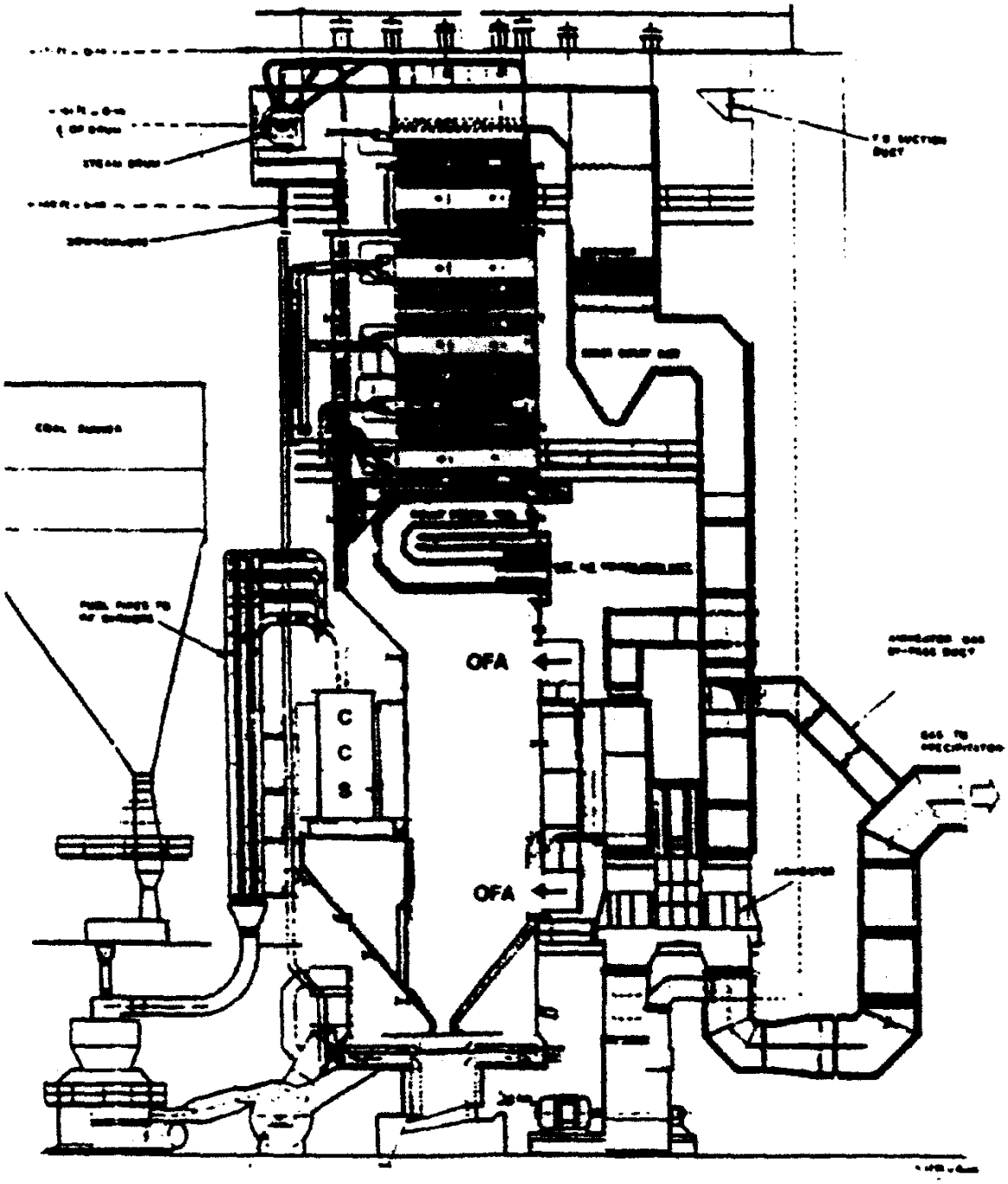

FIGURE 2. CCS PC Boiler Retrofit Concept

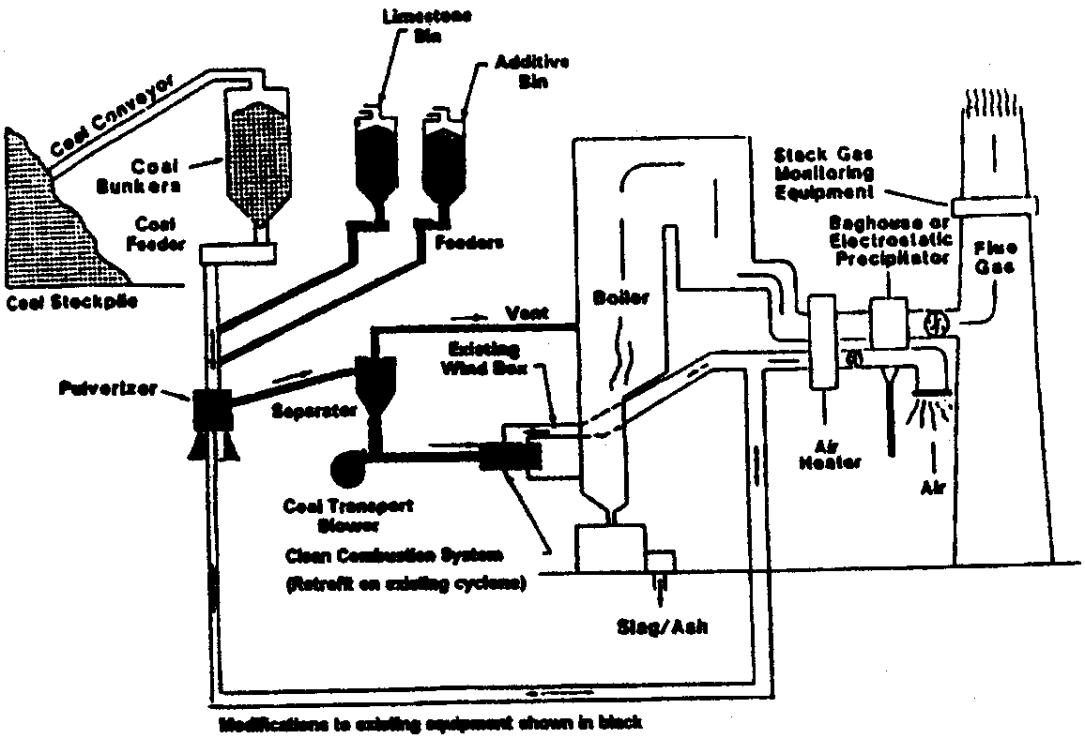

FIGURE 3. CCS Cyclone Retrofit Schematic

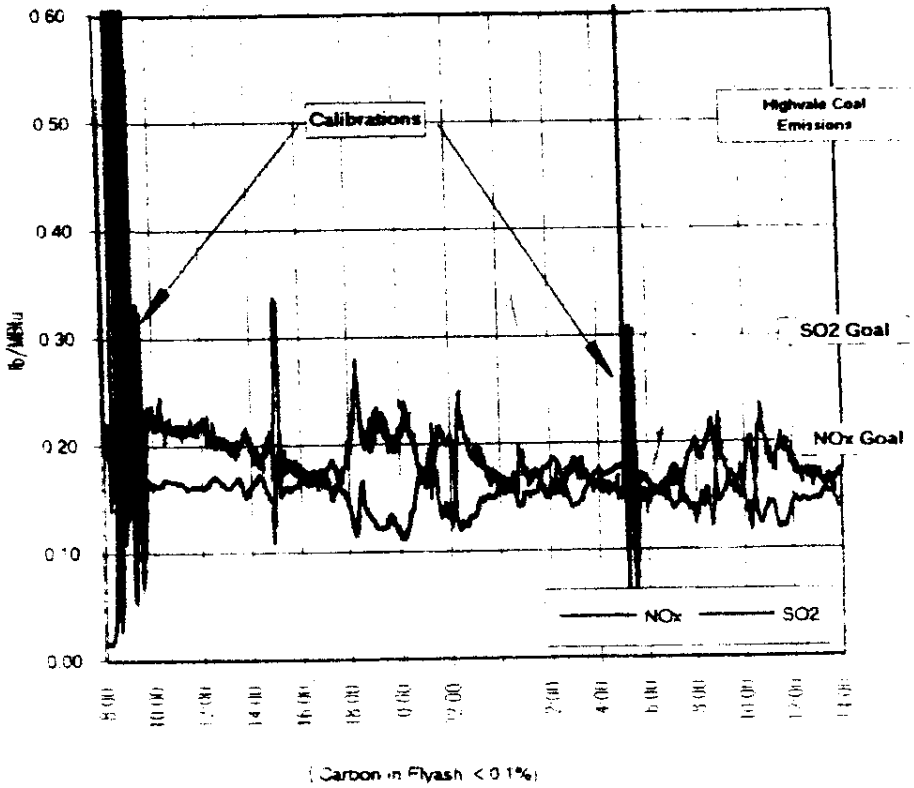

FIGURE 4. LNS-CAP SO_2 and NO_x Stack Emissions

APPENDIX G
Selected Comments on the Report, Increasing Electricity Availability From Coal-Fired Generation in the Near-Term

Pam Martin

From: Ernesto Corte [ecorte@attglobal.net]
Sent: Tuesday, April 17, 2001 10:46 PM
To: 'Pam Martin'
Subject: RE: DRAFT - Executive Summary for the Electricity Availability Report

Executive Summary - General Comments

- Page 2, 2nd paragraph, first sentence. This statement is simply exaggerated; there has not been a dramatic rise in electricity demand throughout the country.
- Page 2, 3rd paragraph, first sentence. As already documented in the April 11 email from AEP, these numbers are wrong.

Executive Summary - Editorial Comments

- In the first sentence of the first paragraph the two commas which are there should be removed. These are commas that Microsoft Word erroneously sticks into various sentences.
- In the last paragraph of the first page, the second sentence ends, "...clean coal technology generations facilities." I believe that the sentence will read better by leaving out the word 'generations' altogether -- or it should be either 'generation' or 'generating', depending upon the meaning desired.
- Page 2, 1st paragraph, last sentence. 'Dependent' is mis-spelled.
- Page 2, 2nd paragraph, next-to-last sentence. I don't know what is meant by power 'quality'. I suspect that a better noun would be 'reliability' or 'dependability'.
- Page 3, 1st sentence. There should be no comma between 'sources' and 'as well'.
- Page 3, the last paragraph. This paragraph is nothing more than a bulletized restatement of the paragraph immediately preceding it, and it should be deleted.

1st Draft of Section - General Comments

- Area 6, item b. We recommend the addition of an important item, by inserting the words 'and fuel quality' following "...a wider range of load..."

1st Draft of Section - Editorial Comments

- Second paragraph of Introduction. A hyphen is needed between 'technology' and 'based'.
- Area 3, second sentence. 'affect' needs to be replaced by 'effect', since it's a noun.
- Area 6, 1st sentence. The compound verb which follows the subject requires that either a verb (recommend 'reduce') be placed in front of 'plant startup times', or replace the comma between 'emissions' and 'plant' with 'and'.

1st Case Study (Fossil Plant EFOR Reduction Program) - Editorial Comments

Section 3, Results. The text preceding the table seems to be in a smaller font than the rest of the document.

The column headings in the two tables in this section need to be cleaned up. The use of '1.1', '1.2', and '1.3' should be eliminated, and the headings should be in one consistent font. Furthermore these tables themselves should be consistent and labeled. At present, one table has gridlines and the other does not.

2nd Case Study (Fossil Plant EFOR/Tube Failure Reduction Program) - Editorial Comments

The third and fourth paragraphs seem to be in a smaller font than the rest of the page. The same problem occurs two pages later.

3rd Case Study (Improvements to Fossil Fuel Power Plant Availability and Reliability) - Editorial Comments

Remove '1.4' in the title.

Change the font in the first paragraph to conform to the rest of the document.

4th Case Study (Coal Fired Unit Turbine Up Rate) - Editorial Comments

Paragraph headings and font are inconsistent with rest of document (in fact the overall labeling of section headings needs to be reviewed throughout the document

5th Case Study (Coal Cleaning Plant Performance) - General Comments

- We found it odd overall that a study was cited in which a coal cleaning plant effected a significant reduction in sulfur content. This is a rare exception in coal mining, probably occurring less than 2% of the time.

5th Case Study (Coal Cleaning Plant Performance) - Editorial Comments

- In the next-to-last paragraph, 'its' should not have an apostrophe.

6th Case Study (Today's Pulverized Coal-Fired Power Generating Technology - General Comments

- Overall this case study could benefit from some improvement in presentation and organization of the material.

6th Case Study (Today's Pulverized Coal-Fired Power Generating Technology - Editorial Comments

- In the second block diagram, the word 'baghouse' is getting cropped.
- In the paragraph under Heat Rate reference is made to Figures 6, but there is no figure labeled as such.
- In the graph following the above paragraph, the x-axis labeling is too small to read AND even if it could be read, it cannot be understood.
- In the paragraph following the graph, in the last sentence, there should not be a comma between 'available' and 'have'.
- In the second graph the sub-heading 'Coal' makes no sense; it is not necessary.
- In the NOx Emissions Performance table the table entries need to be centered.
- In the Mercury paragraph, in the second sentence, there should be a period following '...Removal Systems.'
- In the following sentence there should be " 's " following 'Alabama Power' and 'South Central'.
- On the very next page reference is made to three cases, and then only two are defined.
- In four separate places to mention there are file identifier footnotes which must be removed.

-----Original Message-----
From: Pam Martin [mailto:natcoal@erols.com]
Sent: Thursday, April 05, 2001 8:13 AM
To: 'Agathen, Paul'; 'Aldrich, James'; 'Alexander, Allen'; 'Ali, Sy';

'Altizer, Barbara'; 'Anderson, Gerard'; 'Arvizu, Dan'; 'Bajura, Richard'; 'Beck, Bob'; 'Beer, Janos'; 'Bergman, Klaus'; 'Bird, Jackie'; 'Blackstone, Sandy'; 'Boddy, Charles'; 'Brubaker, Robert'; 'Buck, Louis'; 'Carey, Michael'; 'Cavanaugh, William'; 'Correnti, Maryann'; 'Corte, Ernesto'; 'Courtright, Henry'; 'Craft, Joseph'; 'Crocker, Nicci'; 'Davis, Curtis'; 'Davis, James'; 'Draper, Linn'; 'Dwyer, John'; 'Eimer, Richard'; 'Ellington, John'; 'Ewart, Ellen'; 'Field, Andrea'; 'Gatzemeier, Paul'; 'Gellici, Janet'; 'Goebel, Andrew'; 'Goldberg, Gary'; 'Green, Alex'; 'Grimes, Larry'; 'Hanson, John'; 'Harrison, Clark'; 'Herring, LaDonna'; 'Hipp, Denise'; 'Hollilnden, Jerry'; 'Huffman, Bonny'; 'Jones, Judy'; 'Kelce, William'; 'Knudsen, Valorie'; 'Kraemer, Thomas'; 'Lake, Max'; 'Leer, Steve'; 'Lilly, Peter'; 'Lowman, Ronald'; 'Mahoney, James'; 'Martin, Jim'; 'Mathewson, Chris'; 'Matthews, Charles'; 'Merle, Emmanuel'; 'Middleton, Paulette'; 'Miercort, Cliff'; 'Mitcham, Janie'; 'Mockler, James'; 'Molar,Yolanda'; 'Morris, David'; 'Mulchay, Patrick'; 'Murray, Robert'; 'Narula, Ram'; 'Nelson, Georgia'; 'O'Keefe, Mary Eileen'; 'Ozkan, Umit'; 'Parker, Timothy'; 'Peters, Gordon'; 'Powell, Stephen'; 'Reid, Bill'; 'Richmond, George'; 'Roberts, Karen'; 'Roling, Daniel'; 'Schafer, Bill'; 'Schumacher, Debbie'; 'Sierra, Michael'; 'Smith, Chester'; 'Smith, Dan'; 'Surber, David'; 'Tanselle, Judy'; 'Taylor, Wes'; 'Thomas, Malcolm'; 'Thompson, Paul'; 'Tickner, Dianna'; 'Topazi, Anthony'; 'Torbert, Frank'; 'Trujillo, Arvin'; 'Turnbull, Jane'; 'Turner, John'; 'Verret, Richard'; 'Walton, Kathy'; 'Watkins, Doris'; 'Wendorf, Bud'; 'Whiting, Richard'; 'Wood, James'
Subject: DRAFT - Executive Summary for the Electricity Availability Report
Importance: High

Ladies and gentlemen:

Attached is the latest draft of the Executive Summary for the Electricity Availability Report that the Council is preparing for our May 3 meeting. This draft comes about as a result of the recent meeting of the Coal Policy Committee in Chicago on April 3.

Please review this draft and provide your comments by close of business Thursday, April 12 by phone (202-223-1191), fax (202-223-9031), or e-mail (natcoal@erols.com) to Cassandra Miller , Bob Beck's assistant while Pam Martin
is recuperating from surgery.

Remember, this summary is what most people will read and contains the recommendations that you, as a member of the Council, will give to the Secretary of Energy.

Pam Martin

From: Manoj Guha
mkguha@aep.com
Sent: Wednesday, April 11, 2001 12:00 PM
To: Pam Martin
Cc: 'Ali, Sy'; 'Altizer, Barbara'; 'Arvizu, Dan'; 'Bajura, Richard'; 'Beer, Janos'; 'Bird, Jackie'; 'Blackstone, Sandy'; 'Blumenfeld,Andrew'; 'Brown, Judy'; 'Brownell, Bill'; 'Brubaker,Robert'; 'Buck, Louis'; 'Busch, Fred'; 'Carpenter, Tami'; 'Cook, Sonny'; 'Corte, Ernesto'; 'Crane, Charles'; 'Dalton, Stuart'; 'DePriest, William'; 'Ewart, Ellen'; 'Gehl, Steve'; 'Gellici, Janet'; 'Goodwin, Jerry'; 'Grahame, Thomas'; 'Greene, Carlton'; 'Hanson, John'; 'Harrison, Clark'; 'Hollinden, Jerry'; 'Jenkins, Steve'; 'Jones, Judy'; 'Kane, Bob'; 'Lilly, Peter'; 'Martin, Jim'; 'McWay, Patrick'; 'Murray, Robert'; 'Narula, Ram'; 'Nelson, Georgia'; 'O'Connor, Terry'; 'O'Keefe, Mary Eileen'; 'Peters, Gordon'; 'Powell, Steve'; 'Roberts, Karen'; 'Rogan, Byers'; 'Schafer, Bill'; 'Surber, David'; 'Tanselle, Judy'; 'Watkins, Dorris'; 'Williams, Jacob'
Subject: Re: DRAFT - Executive Summary for the Electricity Availability Report

Electric ExSum.doc

I have reviewed the draft document titled, "Executive Summary", and I tried to make changes in the document but was not able to do so. Therefore, I am writing my comments here separately:

Findings: Page1 ,Line 3, Actually there are currently no environmental barriers for installing clean coal technologies(since they are environmentally superior than the existing technologies and emit much lower emissions than the EPA clean air requirements), as it is depicted here in the document. The economic issues are the major barriers since these technologies are not competitive with either the existing plants/technologies or the combined cycle natural gas-fired plants. However, there may be some barriers to retrofit these technologies with respect to environmental/regulatory issues. But they are relatively minor when compared to economic issues. So the statement should not say that there are regulatory barriers for installing clean coal technologies.
Furthermore, at this time it can not be estimated how many megawatts could be retrofitted with more efficient CCTs.
However, in general existing plants could be more efficiently operated and hence could reduce emissions to the air. Most important point in this respect, however, is that on average an additional 3 to 5% more capacity can be achieved from the existing coal-fired plants (no retrofitting of CCTs required, but require operational changes) but because of the regulatory requirements (NSR problem) that are not rational, no power plant operators will take chances to do so.

Findings: Page 2, Paragraph 3, At the end of 2000, there were 278,000 MW summer and 297,000 MW winter capability for coal-fired generation in the utility sector and 43,000 MW in summer and 48,500 MW in winter capability for coal-fired generation in the non-utility generation sector. Therefore, the maximum capability for coal-fired generation is 321,000 MW in summer and 345,500 MW in winter. For generation and calculation purposes the summer capability is asumed as the generation capability. Therefore the 393,000 MW capability used here in the document is wrong figure. As a matter of fact, total steam electric capability at the end of 2000 was slightly less than 393,000 MW that include approximately 67,000 MW of dual-fired generation (petroleum and natural gas).
According to latest EIA data, the planned additional capacity is 96000 MW in next five years, 230,000 MW in ten years, 313,000 MW in 15 years and 393,000 MW in 20 years. At the same time planned retirement in the same time period are 26,000 MW; 41,000 MW; 59,000 MW; and 69,500 MW

respectively. (Please refer to Page 140 and 141 of the Energy Information Administration/ Annual Energy Outlook 2001, Reference Case Forecast, Table A-9 Electricity Generating Capability). 271,000 MW addition (wherever it may have come from) in the next five years does not seem to be correct.

The last sentence in Page 2 is misleading. It should be clearly stated that it is not only the additional capacity during the peak demand that is important , but it is the equivalent availability factor (EAF) which is more important during the peak demand . In general, reducing the unavailability (and hence, increasing the EAF) during the peak demand will require additional investment wheras to obtain additional capacity will require additional capital investment as well as some regulatory changes. Without assurance from EPA with respect to NSR, no utility operator will make any additinal investment either to increase capacity and/or increase EAF.

Recommendation: I do not agree with the second bullet though it is correct in one sense. It should be clearly mentioned that without the strategy of deploying these technologies which may require either federal and state subsidies and/or tax credits, these technologies can not penetrate the marketplace. Therefore, the U.S. Congress and the Department of Energy will have to play more important role to promote these technologies, Clearly there are no regulatory barriers that create obstacles to introduce these technologies.

If any of the recepients of these comments have any suggestions and/or want to discuss this with me, please do not hesitate to call me at (614)223-1285. However, I will be out of town until monday (4/16/01).

"Pam Martin" <natcoal@erols.com> on 04/05/2001 12:36:33 PM

To: "'Ali, Sy'" <sy.a.ali@rolls-royce.com>, "'Altizer, Barbara'" <barb@netscope.net>, "'Arvizu, Dan'" <darvizu@ch2m.com>, "'Bajura, Richard'" <bajura@wvu.edu>, "'Beer, Janos'" <jmbeer@mit.edu>, "'Bird, Jackie'" <jbird@odod.state.oh.us>, "'Blackstone, Sandy'" <gillesfamily@uswest.net>, "'Blumenfeld,Andrew'" <ablumenfeld@archcoal.com>, "'Brown, Judy'" <brownju@kennecott.com>, "'Brownell, Bill'" <bbrownell@hunton.com>, "'Brubaker,Robert'" <rbrubaker@porterwright.com>, "'Buck, Louis'" <BuckL@conedsolutions.com>, "'Busch, Fred'" <fredb@savageind.com>, "'Carpenter, Tami'" <tscarpen@duke-energy.com>, "'Cook, Sonny'" <dgcook@duke-energy.com>, "'Corte, Ernesto'" <ecorte@attglobal.net>, "'Crane, Charles'" <ccrane@tristategt.org>, "'Dalton, Stuart'" <sdalton@epri.com>, "'DePriest, William'" <william.depriest@slchicago.infonet.com>, "'Ewart, Ellen'" <eewart@ftenergy.com>, "'Gehl, Steve'" <sgehl@epri.com>, "'Gellici, Janet'" <info@westcoal.org>, "'Goodwin, Jerry'" <sjreynolds@nipsco.com>, "'Grahame, Thomas'" <thomas.grahame@hq.doe.gov>, "'Greene, Carlton'" <cegreene@hunton.com>, "'Guha, Manoj'" <mkguha@aep.com>, "'Hanson, John'" <jnha@hii.com>, "'Harrison, Clark'" <clarkh@cq-inc.com>, "'Hollinden, Jerry'" <jerry_hollinden@urscorp.com>, "'Jenkins, Steve'" <steve_jenkins@urscorp.com>, "'Jones, Judy'" <judy.jones@puc.state.oh.us>, "'Kane, Bob'" <robert.kane@hq.doe.gov>, "'Lilly, Peter'" <lilly@triton-coal.com>, "'Martin, Jim'" <james_k_martin@dom.com>, "'McWay, Patrick'" <pmcway@peabodygroup.com>, "'Murray, Robert'"

<bobmurray@coalsource.com>, "'Narula, Ram'" <rnarula@bechtel.com>, "'Nelson, Georgia'" <gnelson@mwgen.com>, "'O'Connor, Terry'" <to'connor@archcoal.com>, "'O'Keefe, Mary Eileen'" <maryeileenokeefe@aol.com>, "'Peters, Gordon'" <gordon@trappermine.com>, "'Powell, Steve'" <spowell@ipalco.com>, "'Roberts, Karen'" <karenr@swps.com>, "'Rogan, Byers'" <jbrogan@pgg.mcdermott.com>, "'Schafer, Bill'" <bschafer@nexgen-group.com>, "'Surber, David'" <surber@surber.com>, "'Tanselle, Judy'" <judy.tanselle@gen.pge.com>, "'Watkins, Dorris'" <dkelleywatkins@evergreen-funds.com>, "'Williams, Jacob'" <jwilliam@peabodygroup.com>

cc:

Subject: DRAFT - Executive Summary for the Electricity Availability Report

Ladies and gentlemen:

Attached is the latest draft of the Executive Summary for the Electricity Availability Report that the Council is preparing for our May 3 meeting. This draft comes about as a result of the recent meeting of the Coal Policy Committee in Chicago on April 3.

Please review this draft and provide your comments by close of business Thursday, April 12 by phone (202-223-1191), fax (202-223-9031), or e-mail (natcoal@erols.com) to Cassandra ??? , Bob Beck's assistant while Pam Martin
is recuperating from surgery.

Remember, this summary is what most people will read and contains the recommendations that you, as a member of the Council, will give to the Secretary of Energy.

(See attached file: Electric ExSum.doc)

Pam Martin

From: WILLIAM.DEPRIEST@sargentlundy.com
Sent: Monday, April 23, 2001 6:06 PM
To: bschafer@nexgen-group.com; natcoal@erols.com
Subject: Re: NCC DOE Report - Technical Section

NCC4-3jm.doc

----- Forwarded by WILLIAM DEPRIEST/Sargentlundy on 04/23/01 04:54 PM -----

WILLIAM DEPRIEST 04/23/01 04:27 PM
To: crkushnir@babcock.com AT nxmime@SNL-ccmail
cc: bschafer@nexgen-group.com AT nxmime, RBeck82851@aol.com AT nxmime
Subject: Re: NCC DOE Report - Technical Section(Document link: WILLIAM DEPRIEST)

Gentelmen:

I have reviewed M. Guha's comments and found that the coal-fired capacity he deduced from the EIA data base is essentially identical to my EIA deduction. I used 325,528MWs of summer based coal capacity as compared to the 321,000MWs proposed by M. Guha. This is only a 1.2% difference and therefore I recommend we not change our findings. I don't know where the 393,000MWs came from that is currently in the overall executive summary. My data shows 241,479MWs of coal capacity older than 20years and 84,049MWs under 20 years old.

See you all in Washington

Bill DePriest

crkushnir@babcock.com AT nxmime 04/18/01 12:09 PM
To: bschafer@nexgen-group.com AT nxmime
nxmime@SNL-ccmail
cc: WILLIAM DEPRIEST/Sargentlundy, RBeck82851@aol.com AT nxmime@SNL-ccmail
Subject: NCC DOE Report - Technical Section

Bill,

Attached to this e-mail is our final copy of the Technical Report being forwarded to you for final clean up and consolidation with the other

1

sections. The version in the attachment contains the exact version that was reviewed in Chicago on April 3 by the NCC Review Committee, with additional potential modifications shown as either sections highlighted in yellow or strike-throughs. This is exactly the same version that I forwarded with my
e-mail on April 5 to you after the Chicago meeting, with the exception that I have numbered the pages to facilitate the comments below.

In regard to the red-lined strike-throughs, and the red typo corrections, you should incorporate those in the final version, in that these are not any changes of significance relative to the NCC Committee review in Chicago.

The primary comment of significance in Chicago, was related to the comment that concerned New Source Review. The issue was raised by Tom Graham of DOE, and it was generally agreed that it was not the intention of the recommendations that the generators would under all circumstances want to avoid NSR. The specific sentence that this discussion centered on was on page 6, Section II, the second paragraph from the bottom. It was agreed that we did not want to convey an image that the coal-fired generators don't want to make any improvements in environmental performance, which is how this sentence could be interpreted. My action item from this discussion was to go back and look at all places in the technical sections where we had referenced technology barriers and in general, it was our intent to not have
these show up in the Technical section, rather to be covered din the Regulatory section. I subsequently discussed this with Bob Beck, and what we agreed was first we would delete the most offending sentence related to NSR, which was discussed in Chicago, and is at the second paragraph from the bottom on page 6. Secondly, I would leave it up to your discretion when you
roll up the Regulatory and the Technical sections and in cases where it makes more sense to leave a regulatory barrier reference in the Technology section, you could do so. If on the other hand, it was more appropriate to delete it, then you should do so and let it be addressed in detail in the Regulatory section. As such, all of the paragraphs that contain comments on
regulatory barriers in the Technical sections are highlighted in yellow in the attachment.

As a final note, Bill DePriest received some feedback from M. K. Guha, of AEP, suggesting that we had overstated the total coal-fired generating capacity in the U.S. Bill is in the process of determining whether this impacts our estimate of the total megawatts that can be recovered by addressing causes of poor availability. He will be providing that feedback shortly. However, if there is a change, I would expect it only to be a small adjustment to the number of megawatts we think can be recovered by getting the availability of the older units up to what's currently being achieved by the modern units.

If you need any additional information, please let me know.

Byers/ck

<<NCC4-3jmtg.doc>>

Pam Martin

From: Tamara S Carpenter [tscarpen@duke-energy.com]
Sent: Thursday, April 12, 2001 12:31 PM
To: Pam Martin; bbrownell@huton.com
Cc: Dorman G Cook Jr; Rickey J Deese; Curtis H Davis; John E Ellington; Nils E Matthews; Mitchell R Hatley
Subject: Re: Coal Policy Draft Study

Critical Regulatory Barriers t...

Electric ExSum.doc

jbr4599r31.doc

I have reviewed the regulatory barriers section and the executive summary and offer the following comments...

I attended the EPRI Environmental Council Sector meeting last week and we discussed this study. One thing we thought needed to be very clear was how much efficiency improvements could reduce emissions from existing coal fired stations. We also need to identify the additional emissions that would be created from a new unit with BACT controls if the same MWs were obtained by building a new generating unit (as opposed to making the existing ones more efficient). Put a number on it.

Regulatory Barriers Section
In the first paragraph, you say "and perhaps additional burdens". I think you can remove "perhaps"and just say "additional burdens".
Where you say "upgrade" ... wouldn't improve be a better description?

In the next to the last paragraph of this section, you discuss the Detroit Edison proposed replacement of the turbine blading, etc. In this section you give very specific numbers for the reduction in pollutants for this efficiency improvement. This is very good. You go on to say that the adoption of this improvement at other units would result in a reduction of CO2 emission of approx 81 million tons per year and correspondingly large reductions in NOx and SO2. I think it would be very good to give a number for SO2 and NOx since these are the regulated pollutants. This would be putting a number on the comment we had at the EPRI Env Sector Mtg.

In the last paragraph of this section, you say ..."This barrier can be expected not only to prevent significant gains in generating capacity, but to actively reduce capacity at these units by preventing needed maintenance." This needs to be elaborated on with it's own paragraph and maybe explained how forced outages would become more common thus reducing availability of the existing MWs. This first sentence also needs to be said in the executive summary.

Executive Summary....
Paragraph 6...

. While not all of this capacity can be targeted for the new technologies discussed in the report, it is estimated that ??? percent of it can be retrofitted with one of these technologies. This additional increase in capacity is estimated at ??? MW and much of it could be brought on line in the next 3 years ...add without increasing emissions from the existing

facility and in some cases, lowering emissions.

Next paragraph....
use improvements instead of upgrades

However, unless there is a significant change in how the installation of new technologies at existing power plants is regulated, it is not likely that any of this additional low-cost, add .....low emission electricity will be produced.

. Removal of this one regulatory barrier would allow plant operators the opportunity to install technologies discussed in the report. If just a 3 percent increase in capacity could be achieved through reducing outages and increasing plant efficiency , it could result in over 11,500 MW being added to current levels. Add something to the effect that in most cases, this would result in a reduction in emissions from these facilities where a newly constructed facility would result in an increase in emissions.

Next paragraph.... Several other existing regulations seem to be in conflict ....here I think you need to specifically mention the Federal Land Manager issue and their ability to delay the siting of new generation.

Thanks for the opportunity to comment. Please call me if you have questions (704)373-7891.

Regards,
Tami.

"Pam Martin" <natcoal@erols.com> 04/05/01 12:45 PM

To: <tscarpen@duke-energy.com>
cc:
bcc:
Subject: Coal Policy Draft Study

For your review, attached is the draft study (comprised of three documents).

Also the following message was sent today (4/5) in regard to the Executive Summary for the Electricity Availability Report:

Ladies and gentlemen:

Attached is the latest draft of the Executive Summary for the Electricity Availability Report that the Council is preparing for our May 3 meeting. This draft comes about as a result of the recent meeting of the Coal Policy Committee in Chicago on April 3.

Please review this draft and provide your comments by close of business Thursday, April 12 by phone (202-223-1191), fax (202-223-9031), or e-mail (natcoal@erols.com) to Cassandra Miller, Bob Beck's assistant while Pam Martin

is recuperating from surgery.

Remember, this summary is what most people will read and contains the recommendations that you, as a member of the Council, will give to the Secretary of Energy.

(See attached file: Critical Regulatory Barriers to Coal.doc)
(See attached file: Electric ExSum.doc)
(See attached file: jbr4599r31.doc)

Pam Martin

From: Clark D. Harrison [cqinc@cq-inc.com]
Sent: Friday, April 06, 2001 7:42 AM
To: Pam Martin
Subject: Re: DRAFT - Executive Summary for the Electricity Availability Report

The Summary is not hard-hitting. It needs to start off with a bulleted list of benefits that can be achieved.

Then, a list of what has to happen, including removal of regulatory barriers, to achieve those benefits.

Then a summary of the report and general statements (policy, public opinion, deregulation, etc.) on our topic.

Recommendations should be last, avoiding the terms support or establish. Use stronger words like lead, initiate, promote, target, instigate, incite, etc.

We have a strong message to deliver and we may only get one chance to influence the new energy policy. Let's be aggressive, but not overtly self-serving.

----- Original Message -----
From: "Pam Martin" <natcoal@erols.com>
To: "'Ali, Sy'" <sy.a.ali@rolls-royce.com>; "'Altizer, Barbara'" <barb@netscope.net>; "'Arvizu, Dan'" <darvizu@ch2m.com>; "'Bajura, Richard'" <bajura@wvu.edu>; "'Beer, Janos'" <jmbeer@mit.edu>; "'Bird, Jackie'" <jbird@odod.state.oh.us>; "'Blackstone, Sandy'" <gillesfamily@uswest.net>; "'Blumenfeld,Andrew'" <ablumenfeld@archcoal.com>; "'Brown, Judy'" <brownju@kennecott.com>; "'Brownell, Bill'" <bbrownell@hunton.com>; "'Brubaker,Robert'" <rbrubaker@porterwright.com>; "'Buck, Louis'" <BuckL@conedsolutions.com>; "'Busch, Fred'" <fredb@savageind.com>; "'Carpenter, Tami'" <tscarpen@duke-energy.com>; "'Cook, Sonny'" <dgcook@duke-energy.com>; "'Corte, Ernesto'" <ecorte@attglobal.net>; "'Crane, Charles'" <ccrane@tristategt.org>; "'Dalton, Stuart'" <sdalton@epri.com>; "'DePriest, William'" <william.depriest@slchicago.infonet.com>; "'Ewart, Ellen'" <eewart@ftenergy.com>; "'Gehl, Steve'" <sgehl@epri.com>; "'Gellici, Janet'" <info@westcoal.org>; "'Goodwin, Jerry'" <sjreynolds@nipsco.com>; "'Grahame, Thomas'" <thomas.grahame@hq.doe.gov>; "'Greene, Carlton'" <cegreene@hunton.com>; "'Guha, Manoj'" <mkguha@aep.com>; "'Hanson, John'" <jnha@hii.com>; "'Harrison, Clark'" <clarkh@cq-inc.com>; "'Hollinden, Jerry'" <jerry_hollinden@urscorp.com>; "'Jenkins, Steve'" <steve_jenkins@urscorp.com>; "'Jones, Judy'" <judy.jones@puc.state.oh.us>; "'Kane, Bob'" <robert.kane@hq.doe.gov>; "'Lilly, Peter'" <lilly@triton-coal.com>; "'Martin, Jim'" <james_k_martin@dom.com>; "'McWay, Patrick'" <pmcway@peabodygroup.com>; "'Murray, Robert'" <bobmurray@coalsource.com>; "'Narula, Ram'" <rnarula@bechtel.com>; "'Nelson, Georgia'" <gnelson@mwgen.com>; "'O'Connor, Terry'" <to'connor@archcoal.com>; "'O'Keefe, Mary Eileen'" <maryeileenokeefe@aol.com>; "'Peters, Gordon'" <gordon@trappermine.com>; "'Powell, Steve'" <spowell@ipalco.com>; "'Roberts, Karen'" <karenr@swps.com>; "'Rogan, Byers'" <jbrogan@pgg.mcdermott.com>; "'Schafer, Bill'" <bschafer@nexgen-group.com>; "'Surber, David'" <surber@surber.com>; "'Tanselle, Judy'" <judy.tanselle@gen.pge.com>; "'Watkins, Dorris'" <dkelleywatkins@evergreen-funds.com>; "'Williams, Jacob'" <jwilliam@peabodygroup.com>
Sent: Thursday, April 05, 2001 12:36 PM
Subject: DRAFT - Executive Summary for the Electricity Availability Report

>
>
> Ladies and gentlemen:
>
> Attached is the latest draft of the Executive Summary for the Electricity
> Availability Report that the Council is preparing for our May 3 meeting.
> This draft comes about as a result of the recent meeting of the Coal
Policy
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> (natcoal@erols.com) to Cassandra ??? , Bob Beck's assistant while Pam
Martin
> is recuperating from surgery.
>
> Remember, this summary is what most people will read and contains the
> recommendations that you, as a member of the Council, will give to the
> Secretary of Energy.
>
>
>
>

Pam Martin

From: Jones, Judy [Judy.Jones@puc.state.oh.us]
Sent: Monday, April 16, 2001 10:51 AM
To: 'Pam Martin'
Subject: RE: DRAFT - Executive Summary for the Electricity Availability Report

Hello Bob,

I apologize for this late response. I hope it is not too late. I have been home with bronchitis for ten days and out of circulation.

I think the executive summary is very good and to the point. I would make a couple of suggestions.

✓ The last sentence before the recommendations could be stronger by saying "Regulation should be harmonized with the energy and national security goals of the country."

✓ Also, since uncertainty has been a problem for utilities and others to build generation etc. another bullet that says "Establish a dialogue with all stakeholders to provide for future regulatory certainty."

All in all a very good paper that will be very useful to the Secretary and Department of Energy.
Thanks for all your hard work on this fast track.

Judy Jones
614-644-8226

APPENDIX H
Acknowledgements

The members of the Working Group wish to acknowledge, with sincere thanks, the special assistance received from the following persons in connection with various phrases of the development of this report:

Byers Rogan, Babcock & Wilcox

Bill Brownell, Hunton & Williams

Bill Schafer, NexGen

Rob Brubaker, Porter Wright Morris & Arthur

Tony Armor, EPRI

Stu Dalton, EPRI

Steve Gehl, EPRI

Janos Beér, MIT

Bill DePriest, Sargent & Lundy

Steve Jenkins, URS Corp.

Ron Litzinger, Edison Mission Energy

Cassandra Miller, NCC Staff (temporary)

Pam Martin, NCC Staff

David Surber, producer, "Make Peace With Nature" TV Show

Julie Clendenin