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LOWERRE & FREDERICK
ATTORNEYS AT LAW
44 East Avenue, Suite 100
Austin, Texas 78701
(512) 469-6000 · (512) 482-9346 (facsimile)
Mail@LF-LawFirm.com

March 31, 2006

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HR APR 03 2006
BY VY

CHIEF CLERKS OFFICE
06 MAR 31 PM 4:59
TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Ms. LaDonna Castanuela, Chief Clerk
Texas Commission on Environmental Quality
Building F, Room 4301
12015 Park 35 Circle
Austin, Texas 78753
P.O. Box 13087
MC-105
Austin, Texas 78711-3087

RSK 49300

FACSIMILE TRANSMISSION
Hard copy to follow. 239-3311

Re: Comments and Hearing Request on the application of and draft permit for State Air Quality Permit No. 45586 and PSD Permit No. PSD-TX-1055

Dear Ms. Castanuela:

Sustainable Energy and Economic Development Coalition (SEED) offers the following comments. SEED requests a contested case hearing on this matter. SEED may be contacted through my office at the letterhead address; Ms. Karen Hadden is the Executive Director of SEED.

Members of SEED are persons who will be affected by the proposed major modification (i.e., the repowering) of the existing E.S. Joslin facility in Calhoun County, Texas. Several SEED members reside in Calhoun County, both in Point Comfort and in Port Lavaca. Others are in neighboring Jackson County or Victoria County. Three SEED members (Mr. John Dugger, Ms. Mary Ann Traylor and Mr. Fred Woodland) are very-nearby ranch owners. These members are concerned about the health impacts of the repowered plant on themselves, their workers and their cattle; additionally, these ranchers will suffer a diminished quality of aesthetic life, because of the plume from the smoke stacks that will obscure portions of the sky at various times, particularly during startup, shutdown and during upsets. Another member (Ms. Ruby Williams) and her husband and children live within 2 miles of the plant; she is concerned about the plant's aesthetic impact and, of course, about the health consequences for herself and her family of the emissions from the plant. At least one SEED member (Tim Strykus) is a fisherman who fishes the bay waters due south of the plant. The repowered plant will occasionally obscure parts of the sky, offending Mr. Strykus's aesthetic sensibilities and, of course, he worries about the impacts of the plant's emissions on his health and that of the fish he catches from nearby waters. Even in the absence of harm-in-fact to his fish catch attributable to the repowered plant, he worries that his customers will value his catch less than they otherwise would, in light of their perception of heavy metals accumulation in fish from the power plant's emissions. At least one other SEED member (Clay Maxwell is a Steelworkers (USA) member and representative; Steelworkers (USA) members work at the immediately adjoining Alcoa World Alumina site, the site at which vanadium ESLs have been modeled to be exceeded because of emissions from the repowered plant; these workers, Mr. Maxwell's constituents, will also suffer increased risk of health harms because of the plant's other emissions. Mr. Keith works well within 2 miles of the repowered plant.

SEED requests the draft permit comment time be extended, inasmuch as all the fuel composition data are allegedly "confidential," and, as such, were not available for analysis by SEED to help with SEED's understanding of contaminants to be emitted or the rates at which they would be emitted. SEED requests an extension to time until two weeks after its "Open Records Request" for these materials has been acted upon.

SEED believes the following issues have not been adequately addressed by the permit application and the resulting draft permit:

1. The emission limits for nitrogen oxides, particulate matter and sulfur dioxide are not protective of the public health;
2. The BACT analysis is incomplete, in that technologies not favored by the applicant were not evaluated for their abilities to limit emissions in technically and economically reasonable fashions;
3. The dispersion modeling used to demonstrate compliance with the NAAQS and to generate off-site receptor impacts improperly estimated SO2 emissions during startup and shutdown and was not based on the appropriate PSDB sources and did not properly model the impacts of H2SO4 emissions or NOx emissions;
4. The vanadium ESL exceedances dictated additional modeling and toxicological work that was not performed;
5. The impacts of mercury and, probably, certain other heavy metal emissions were not adequately considered;
6. It does not appear that all on-site sources of emissions were modeled, and it does not appear that proper emission factors (or, occasionally, emission rates derived from proper emission factors) were utilized in the modeling.
7. The transport of ozone precursors to more remote locales (e.g., Houston/Galveston and Victoria) was not evaluated;
8. The compliance history of the applicant was not properly determined or considered the permitting decision; and
9. Generally, the requirements of the PSD program approved by EPA for implementation by Texas were not met.

Sincerely,

David Frederick

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Mail@LF-LawFirm.com

March 31, 2006

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Texas Commission on Environmental Quality
Building F, Room 4301
12015 Park 35 Circle
Austin, Texas 78753
P.O. Box 13087
MC-105
Austin, Texas 78711-3087

OPA
H APR 04 2006
BY KA

NSR 49300

CHIEF CLERKS OFFICE
APR -3 PM 3:15
TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

FACSIMILE TRANSMISSION
Hard copy to follow. 239-3311

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Sincerely,

David Frederick

Comments and Request for Contested Case Hearing
on the Application for State Air Quality
Permit No. 44586 and PSD Permit #PSD-TX-1055,
submitted by Calhoun County Navigation District;
E.S. Joslin Power Station
For Circulating Fluidized Bed Pet Coke-Coal Boiler at Point Comfort,
Calhoun County, Texas

NSR/49300

Submitted by:

Public Citizen's Texas Office
The Sustainable Energy and Economic Development (SEED) Coalition
Texas Black Bass Unlimited
Sierra Club's Lone Star Chapter
Sierra Club's Coastal Bend Regional Group (Calhoun-Nueces County area)
Alamo Sierra Club Regional Group
Dallas Sierra Club Regional Group
Greater Fort Worth Sierra Club Regional Group
Sierra Club's Cross Timbers Regional Group (Denton County)
Blue Skies Alliance

OPA
SEP 13 2005
BY

September 12, 2005

Ms. LaDonna Castanuela
Chief Clerk, MC-105
Texas Commission on Air Quality
PO Box 13087
Austin, Texas 78711-3087

Dear Ms. Castanuela,

A number of the members of Public Citizen, the SEED Coalition, Sierra Club and Blue Skies Alliance request a contested case hearing. The commenters are all membership organizations with members who will be affected by the proposed major modification at the existing E.S. Joslin utility to construct and operate a petroleum coke, coal-fired plant in Calhoun County, Texas. The application is for adding a new circulating fluidized bed boiler and modifying turbine for 300 MW electricity generation.

Public Citizen's mission is to assure that the products we use (including electricity) are safe when we use them, when we manufacture them, or when we dispose of them. Public Citizen currently has 5 members in Calhoun County.

SEED's mission is to promote economic development in Texas though

clean energy. SEED also educates the public about the economic, environmental, and health benefits of a sustainable energy strategy. The SEED coalition has roughly 600 members in the Point Comfort, Victoria, San Antonio, Corpus Christi, Austin , and Dallas-Fort Worth areas.

The Texas State Sierra Club's Lone Star Chapter mission is protect air quality, the environment and public health and has 26,675 members with more than 440 members in the Coastal Bend Regional group, including the Calhoun County area and adjacent counties. The Alamo Sierra Club Regional group has more than 2300 members in the San Antonio area.

Blue Skies Alliance's (BSA) mission is to promote healthy air quality for the citizens of North Texas. BSA represents approximately 4,000 citizens through mailing lists, e-mail lists and monthly meetings.

Texas Black Bass Unlimited has approximately 2000 members in Texas.

Many members are concerned about a deterioration of their air quality from many new coal-fired power plants and urge the organizations to request a contested case hearing. In addition, we have members who suffer from asthma and respiratory illness that would be directly affected by a new petroleum coke-coal-burning power plant.

We request a contested case hearing on the proposed draft permit. On behalf of our members in Point Comfort, Victoria, San Antonio, Corpus Christi, Austin, Waco and Dallas-Fort Worth, we oppose the proposed Calhoun County Navigation District/s E. S. Joslin application and draft permit on the grounds that it does not appear to be protective of public health, quality of life, or private property that will be impacted by the air emissions from this plant.

The Calhoun County Navigation District's E. S. Joslin application according to Table PSD-1, page 2 shows a proposed increase of 813 tons per year (tpy) of NOx, 1741 tpy of CO, 70 tpy of VOC, 174 tpy of PM, 1138 tpy of SO2, abd 35 tpy of sulfuric acid mist/H2SO4. Due to the proposed emissions increases, PSD review was triggered for the above six pollutants since they are above the PSD significance levels.

Due to recent shutdown of existing gas-fired boiler facilities at the Joslin facility, contemporaneoius credits are allowed as follows from Tables PSD-2 & -3:
NOx credits of 473 tpy resulting in a net increase in 340 tpy of NOx;
CO credits of 154 tpy resulting in a net increase of 1587 tpy of CO;
VOC credits of 7 tpy resulting in a net increase of 63 tpy of VOC;
PM credits of 16 tpy resulting in a net increase of 158 tpy of CO, and
SO2 credits of 29 tpy resulting in a net increase of 1109 tpy of SO2.

The combined net increase will produce more than 3,257 tpy of new normal operating emissions in addition to the prior normal style emissions of 679 tpy from the old gas-fired boiler. Total new plant stack emissions during normal operations are projected at 3,936 tpy.

CFB boiler emissions during start-up/maintenance operations burning natural gas are projected to be 553 tpy of NOx, 929 tpy of CO, 61 tpy of VOC, 84 tpy of PM, and 7 tpy of SO2 for a total of 1,634 tpy. Joslin's prior start-up/maintenance emissions do not appear to be in the application but are likely to be significantly less for a gas-fired boiler than a larger pet coke-coal-fired boiler.

Total normal and start-up/maintenance emissions are estimated at 5,570 tpy including 1,839 tpy of NOx.

We request contested case hearing on the application and projected draft permit. We have laid out 18 areas for which the application itself and the projected draft permit is also likely to be inadequate.

1. The emission limits for nitrogen oxides, particulate matter and sulfur pollution are not protective of public health.

2. The application and projected draft permit do not require offsets of any pollutant type. Nitrogen oxides, sulfur dioxide and carbon pollution are of particular concern.

3. The projected 1,839 tons per year of total NOx emissions from this plant would affect the ability of the DFW area to come into attainment with the 1-hour and 8-hour ozone standards. Higher NOx emissions from this plant would cause or contribute to North Texas smog rendering the Dallas SIP ineffective to come into compliance with the federal health-based ozone standards.

4. The BACT analysis performed in the permitting process does not fully explore the best available control technologies. Specifically, CCND did not adequately consider or propose Integrated Gasification Combined Cycle (IGCC) as part of their BACT analysis.

5. The application (and projected draft permit) do not utilize best available control technologies for sulfur pollution as established by an application filed prior to this one for the City Public Service plant in San Antonio.

6. The application (and projected draft permit) do not adequately examine the impact of the NOx, SO2 and PM emissions on Class I areas such as Big Bend.

7. The application (and projected draft permit) do not examine the opportunities for obtaining sulfur and mercury emissions reductions through coal washing.

8. **The application (and projected draft permit) do not examine the opportunities to reduce emissions by using lower emissions fuels.**

9. **The application (and projected draft permit) do not address global warming gases which clearly should be regulated by the TCEQ.** The TCEQ has the authority and the responsibility to regulate global warming gases and must do so.

10. **The application (and projected draft permit) do not adequately manage emissions during start-up and shutdown.**

11. **The application (and projected draft permit) do not adequately manage fugitive emissions both from coal and ash handling and during start-up and shutdown.**

12. **The mercury emissions for this plant do not meet the BACT standards established for these plants by the draft permits issued by the TCEQ in the Spruce 2** and Sandy Creek applications given E.S. Joslin's projected 60 pounds per year.

13. **The TCEQ must implement more comprehensive baseline ambient air monitoring in Point Comfort, Texas.**

14. **The application (and projected draft permit) do not consider the diesel and particulate pollution that would result from the trains that would bring coal to this plant.**

15. **Air toxics that would come from this plant are not adequately addressed. Also, the toxicology review also does not address short-term SO2 spikes.**

16. **The application (and projected draft permit) must state what specific equipment makes and models will be used for the boiler and control equipment as well as the manufacturer guaranteed emissions levels from this equipment. Petroleum coke is a toxic oil refining byproduct that needs to adequately controlled at the E.S. Joslin power station.** The application and TCEQ information project 95% control efficiency without providing sufficient details on the manufacturer or testing to confirm 95% will be achieved.

17. **Texas Effects Screening Levels (ESLs) have not been appropriately defined by the TCEQ.**

18. **The TCEQ should be regulating radon and its carcinogenic byproducts that the public will be exposed to as a result of this plant.**

The citizens of Point Comfort, Texas and downstream communities of Victoria, San Antonio, Austin and Dallas Fort Worth have serious concerns about the impacts that this plant will have on air quality, public health, quality of life, and economic growth in their communities. As is described in the following pages, the draft permit for the proposed Calhoun County Navigation District (CCND) plant is severely flawed in several areas. A comparison of the draft permits for CCND's petroleum-coke, coal-fired power plant and a comparable plant proposed by City Public Service (CPS) in San Antonio shows that the CCND allowable emission levels would not be as protective of public health as those proposed for the CPS plant.

1. The emission limits for nitrogen oxides, particulates and sulfur pollution are not protective of public health.

The emission limits for both particulate emissions and sulfur emissions in the draft permit for CCND are greater than the corresponding limits for the proposed City Public Service plant in San Antonio. Calhoun County Navigation District's proposed plant should be held to the same emissions limits as those that have been determined for the plant in San Antonio.

CPS is offsetting nearly all of its sulfur emissions by reducing this pollution at other power plants. E.S. Joslin on the other hand is being allowed significant rates of higher air pollution and is only offsetting approximately 20% of total normal operating emissions or less if start-up/maintenance emissions are considered. As part of the requested permit, E. S. Joslin is using credits for existing sulfur emissions of 29 tpy or less than 3% of the new plant's normal SO2 emissions of 1138 tpy for a large increase of more than 97%. **Thus the CCND plant would add nearly 30 times more sulfur pollution and a much higher rate of particulate matter pollution to Texas skies compared to another new plant in San Antonio.**

Particulate pollution from power plants has serious health impacts, leading to asthma attacks, heart attacks and to premature death. Particulate matter from power plants cuts short over 1000 lives each year in Texas, taking 14 years on average from each life.

Calhoun County Navigation District has increased their allowable particulate pollution from this plant to unacceptable levels. The particulate emission rate limit in Calhoun County Navigation District's projected draft permit is much higher than that proposed for a new power plant in San Antonio.

In addition, sulfur pollution from the E.S. Joslin plant will lead to the formation of secondary particulate matter which is also known to have serious health hazards.

	SO2 (tpy)	PM (tpy)	SO2 (lb/mmbtu)	PM (lb/mmbtu)

San Antonio Plant	36	831	0.06	0.022
Point Comfort Plant	1,109	174	0.10	0.04

In addition, nitrogen oxides pollution from the E.S. Joslin plant will lead to the formation of secondary particulate matter which is also known to have serious health hazards. Nitrogen oxides increases will be a 40% jump over the existing plant and by including start-up/maintenance NOx emissions, it results in potentially a net increase of 47% NOx.

A 2004 study by the Clean Air Task Force (CATF) has estimated that the Dallas-Fort Worth-Arlington metro area experiences the following health impacts each year due to particulate pollution from coal-fired power plants:
290 premature deaths each year, plus
476 heart attacks
38 lung cancer deaths, and
over 10,000 asthma attacks, over 500 of which require a visit to the emergency room

The CCND plant would add to these health effects as well as deteriorating public health in and around Point Comfort.

The analysis for the Clean Air Task Force study was done by ABT and Associates, the same firm that has performed modeling for the EPA. This study provides the best evidence to date for fine particles' link to a broad range of effects leading to hospitalization and premature death. While previous studies established the link between fine particles and asthma-related hospital admissions, including a 1999 study which confirmed the relationship between increases in fine particle pollution and hospital admissions for asthma, the CATF study reviews the associations between fine particle levels and increased hospital admissions for cardiovascular disease, pneumonia, and chronic obstructive pulmonary disease from power plants. For Texas it was estimated that 1,160 people die early each year because of their exposure to fine particle pollution from coal-fired power plants.

Emergency Room Visits

Several other important studies tie fine particle levels to emergency room visits. For example, fine particles were associated with emergency room visits for asthma in Seattle, Washington; Barcelona, Spain; and Steubenville, Ohio.4 Studies have linked air pollution with both hospital admissions and emergency room visits. There is more data on hospital admissions that allows researchers to derive more complete estimates.

While these studies of hospital admissions and emergency room visits provide evidence that exposure to fine particles is directly associated with asthma attacks, researchers have also examined the relationship between air pollution and less severe asthma attacks that do not result in hospitalization. Studies in Denver, Los Angeles, and the Netherlands found that substantial increases in asthma attacks were linked with fine particle exposure.

Other Respiratory Symptoms
Many other studies have also found a link between fine particle pollution and a whole range of well-known upper and lower respiratory symptoms including: deep, wet cough; running or stuffy nose; and burning, aching, or red eyes. Associations between fine particles and more general measures of acute disease have also been found. For example, one study evaluated the impact of fine particle levels on lost work days from workers calling in sick, an association that suggests an impact of air pollution on the U.S. economy, while other studies link particles and non-work restricted activity.5

Extensive new research published over the past year finds that fine particles at levels routinely found in many U.S. cities may trigger sudden deaths by changing heart rhythms in people with existing cardiac problems. While further research is needed, these early studies are extremely important because cardiovascular disease is the number one killer in the United States, responsible for nearly half of all deaths. While heart rhythms in healthy persons remain largely unaffected by fine particle pollution, for those with existing heart disease fine particle exposures could have deadly consequences. The threat seems particularly acute for elderly people who have existing heart arrhythmia (a life-threatening condition of rapid, skipped or premature beats) or the combination of a weak heart and lung disease such as asthma. The studies suggest that people are dying within 24 hours after elevated particulate matter exposures. About a dozen major scientific studies in the United States, recently completed or underway, are turning up evidence of heart pattern changes in animals exposed in laboratories and in elderly people tested in nursing homes.

Several PM10-health effects studies, published in 1994 and 1996, show associations between health effects and a small daily increase in PM.

According to a 1994 Harvard study, the PM levels from the CCND's plant will result in health effects. This study found a broad range of respiratory and cardiovascular effects from fine particulate matter. This study found the following increases in health impacts for every 10 mg/m3 increase in ambient PM10 levels.,

Health Impacts **Increase associated with 10 mg/m3 Increase in Particulate Pollution**
Increase in Daily Mortality
Total Deaths
Respiratory Deaths
Cardiovascular Deaths
1.0% increase
3.4% increase
1.4% increase
Increase in Hospital Usage (All respiratory)
Admissions
Emergency Room Visits
0.8% increase

1.0% increase Exacerbation of Asthma
Asthmatic Attacks
Bronchiodilator
Emergency Room Visits
Hospital Admissions
3.0% increase
2.9% increase
3.4% increase
1.9% increase Increase in Respiratory Systems Reports
Lower Respiratory
Upper Respiratory
Cough
3.0% increase
0.7% increase
1.2% increase Decrease in Lung Function
Forced Expired Volume
Peak Expiratory Flow
0.15% increase
0.08% increase

Thus, the TCEQ has considered a lethal daily increase in PM10 to be acceptable.

The public health concern being raised is that the potential exists for a modeled daily PM10 pollution increase of 10 μg/m3 or higher from Calhoun County Navigation District may be lethal since it will result in health effects including increased premature mortality from cardiovascular and respiratory deaths and other adverse health effects. The CCND plant site will be located directly upwind of the nearby Point Comfort community.

The PM10 modeling in Section VI Air Quality Analysis (p. 6 Preliminary Determination Summary, Table - Modeling Results for PSD NAAQS - Above De Minimis) presents the modeling results indicating the predicted increased daily PM10 emissions due to the Calhoun County Navigation District plant. The potential exists for modeled daily PM10 increase of 10 micrograms per cubic meter or greater as the GLCmax. This raises serious concerns that the Calhoun County Navigation District plant will produce a range of adverse health effects from its maximum particulate matter emissions rate of 174 tons per year that TCEQ may move to approve in the draft air quality permit. Health effects studies published in peer-reviewed journals presented a strong association between a daily 10 micrograms per cubic meter increase in PM10 and particulate health effects including premature deaths. When Calhoun County Navigation District is emitting a maximum allowable rate of approximately 40 pounds per hour of PM10 (instantaneous pounds per hour emissions rate based on annual maximum 174 tons per from the application tables), the plant's potential daily PM10 increase of 10 micrograms per cubic meter or greater will be above the daily 10 micrograms per cubic meter increase in PM10 recognized for measured health effects.

Health effects of PM10 pollution increases may be observed for several days after peak exposures, and detectable for up to several weeks after substantial air pollution episodes. At relevant concentrations the mortality dose response relationship is essentially linear, with increases in mortality seen even at very low exposures in micrograms per cubic meter.

The TCEQ's review of the Calhoun County Navigation District permit application does not appear to take into account the health effects from a daily 10 or more micrograms per cubic meter increase in the Point Comfort community area from the plant's operations at less than the maximum boiler firing rates resulting in such a daily PM10 increase.

The TCEQ also has not properly evaluated the health effects from CCND's potential daily increase of 10 or more micrograms per cubic meter increase at maximum plant operations, or the potential for additional health effects occurring for several days after peak exposures as observed in published peer-reviewed studies. The TCEQ has also not evaluated the additional impacts of daily PM2.5 emissions from possible diesel locomotives to the CCND plant's maximum PM10 daily emissions, which will exacerbate the health effects from the potential PM10 increase of 10 or more micrograms per cubic meter. The CCND application did not include sufficient details on the number of coal trains delivering coal to the Joslin plant, but clearly describes coal handling and transfer operations including outdoor, open air coal storage facilities.

Background daily PM10 pollution around the Calhoun County Navigation District's plant site needs to be considered due to nearby major industrial sources such as Formosa Plastics, Alcoa and other facilities in Point Comfort. A large potential exists for significant background PM10 in micrograms per cubic meter and combined with a potential for modeled PM10 increase of 10 or more micrograms per cubic meter, results in a potential for Total PM10 Concentration [Background + GLCmax] of unsafe PM10 levels in micrograms per cubic meter at the Calhoun County Navigation District plant's property line.

Based on reviews of other draft permits for coal-fired power plants, a concern is that the projected modeled daily PM10 increase will not take into account secondary particulate formation from SO2 and NOx emissions between the stack exit point and the GLCmax area along the Calhoun County Navigation District plant's property line. A modeled daily PM10 increase potentially of 10 or more micrograms per cubic meter may therefore be an underestimation of the total daily PM10 increase at the GLCmax.

In the largest study of its kind published in JAMA, a group of 500,000 adults were followed for 16 years and PM2.5 monitoring data collected and 11 other cofounders compared. The study's objective was "To assess the relationship between long-term exposure to fine particulate air pollution and all-cause, lung cancer, and cardiopulmonary mortality." The researchers conclusion: "Long-term exposure to combustion-related fine particulate air pollution is an important environmental risk factor for cardiopulmonary and lung cancer mortality." In their results, they emphasized that "Fine particulate and sulfur oxide-related pollution were associated with all-cause, lung cancer, and cardiopulmonary mortality. Each 10-μg/m3 elevation in fine particulate air pollution was associated with approximately a 4%, 6%, and 8% increased risk of all-cause, cardiopulmonary, and lung cancer mortality, respectively. Measures of coarse particle fraction and total suspended particles were not consistently associated with mortality."

"Associations have been found between day-to-day particulate air pollution and increased risk of various adverse health outcomes, including cardiopulmonary mortality. However, studies of health effects of long-term particulate air pollution have been less
conclusive."

The American Heart Association issued a Scientific Statement on Air Pollution and Cardiovascular Disease in June 2004 that focused on the association between cardiovascular morbidity and mortality and PM pollution.

According to this review of data on fine particles and health effects, the AHA determined that there is a clear potential to improve the national public health and to substantially reduce cardiovascular morbidity and mortality by reducing PM levels to current EPA standards.

The AHA found that "...the existing body of evidence is adequately consistent, coherent, and plausible enough to draw several conclusions. At the very least, short-term exposure to elevated PM significantly contributes to increased acute cardiovascular mortality, particularly in certain-at-risk subsets of the population. Hospital admissions for several cardiovascular and pulmonary diseases acutely increase in response to higher ambient PM concentrations. The evidence further implicates prolonged exposure to elevated levels of PM in reducing overall life expectancy on the order of a few years."

"On the basis of these conclusions and the potential to improve the public health, the AHA writing group supports the promulgation and implementation of regulations to expedite the attainment of the existing National Ambient Air Quality Standards. Moreover, because a number of studies have demonstrated associations between particulate air pollution and adverse cardiovascular effects even when levels of
ambient PM2.5 were within current standards, even more stringent standards for PM2.5 should be strongly considered by the EPA."

Another study done in 2001 studied the relationship between particulate pollution and the triggering of myocardial infarction. This study found a 44% increase in heart attacks within 2 hours of PM2.5 exposure and 33% increase within 4 hours of PM2.5 exposure.

This study suggests that elevated concentrations of fine particles in the air may transiently elevate the risk of myocardial infarctions within a few hours and 1 day after exposure.

Evidence shows that the EPA's standard is not protective of public health.

TCEQ relies on the EPA's national ambient air quality standards for PM10 adopted in 1987. However, the EPA PM10 NAAQS are less protective than the California PM10 state AAQS and the comments here address why the California Air Resources Board relies on such protective PM10 standards. As it turns out, the EPA, in setting the national annual PM10 standard, did not consider the carcinogenic potential of long-term exposure to PM10. In addition, in setting the national daily PM10 standard, the EPA did not consider the premature deaths resulting from short-term exposure to PM10. The presentation explains the significance of weak EPA PM10 standards which fail to protect public health.

A 1991 report by the California Air Resources Board (CARB) states that CARB uses a daily PM10 standard of 50 µg/m3, as opposed to the EPA's daily PM10 standard of 150 µg/m3, because EPA's standard does not address premature death. This report states that the annual EPA standard of 50 µg/m3 (CARB uses 30 µg/m3) is also not protective of public health since it does not address the carcinogenic potential of long-term exposure to PM10.

"In 1969, the Board established the standards for total suspended particulate matter or "TSP" which considered all the particles in the air. In December 1982, the Board rescinded the TSP standards and adopted standards for PM10. The PM10 standards are roughly equal in stringency to the previous TSP standards. However, the PM10 standards are more closely related to the actual effects of particles on human health because the PM10 standards address the particles small enough to reach the human lung. By expressing the standards in terms of PM10, the Board directed that control efforts focus on reducing the ambient particles that are most damaging to human health.

The Board adopted the PM10 standards to protect the public from the health effects of short-term exposure to ambient PM10 (the 24-hour PM10 standard) and long-term exposure (the annual PM10 standard). The 24-hour standard [set at 50 µg/m3] is based on studies which show that people with serious respiratory illnesses suffer increased death rates when exposed to increase concentrations of ambient PM10. The annual standard [set at 30 µg/m3 as an annual geometric mean] is based on studies which show that long-term exposure to PM10 causes decrease breathing capability and increased respiratory illness in susceptible populations such as children. The annual standard is also based on a consideration of the substances in PM10 that cause cancer.

The PM10 standards are expressed as a weight of PM10 particles per volume of air. There is no consideration of the size or the chemical make-up of the particles although these are important factors in terms of the health risks associated with PM10 (see previous section). The state PM10 standard is 50 micrograms per cubic meter. The state annual PM10 standard, calculated as the annual geometric mean of the 24-hour concentrations, is 30 micrograms per cubic meter. The Board established both of the state PM10 standards as concentrations not to be exceeded.

In addition to the state PM10 standards, there are national PM10 standards. The EPA established the national PM10 standards during July 1987. The national 24-hour PM10 standard is 150 micrograms per cubic meter. The national annual PM10 standard is 50 micrograms per cubic meter, calculated as an annual arithmetic means.

Obviously, the state 24-hour PM10 standard is substantially more stringent than the national 24-hour standard. The adverse health effects the Board considered during the adoption of the state standard were premature death and respiratory illness. The populations at risk included individuals with prior respiratory health problems. The California Department of Health Services (the DHS) found that these serious health effects occur at PM10 levels well below what is now the national 24-hour PM10 standard.

In contrast, the national PM10 standard was based primarily on reversible decreases in respiratory function, and not premature death. The populations at risk were school aged children with normal health status, not necessarily individuals with prior respiratory health problems. The PM10 levels at which these health effects occurred were higher than those found by the DHS to cause premature death in sensitive segments of the population.

The results and analyses of studies published subsequent to the Board's adoption of the state 24-hour PM10 standard suggest strongly that the national 24-hour PM10 standard does not include any margin of safety, and therefore it does not adequately protect health.

The state 24-hour PM10 standard is primarily based on two studies. One study demonstrated increased illness in London patients with bronchitis. The other study showed that there were increased deaths in London during periods with high particle concentrations. The particle concentrations in both of these studies were reported as British Smoke and were mathematically converted to equivalent PM10 concentrations using a two-step conversion process. The British Smoke measurements were first converted to TSP concentrations, based on data from collocated instruments that measured British Smoke and TSP. (These instruments were operated in London.) The TSP concentrations were then converted to equivalent PM10 concentrations based on data that measured TSP and PM10. (These instruments were operated in the United States.) In adopting the state 24-hour PM10 standard, the Board also considered the recommendations of the California Department of Health Services.

The national 24-hour PM10 standard is based primarily on a study of decreased lung function in children living in Steubenville, Ohio. The study demonstrated that the decrease in lung function was closely associated with an increase in particle concentrations. The particle concentrations reported in this study were measured as TSP and were mathematically converted to equivalent PM10 concentrations. The conversion was based on collocated measurements of TSP and PM10 from Steubenville.

The state and national annual PM10 standard levels also differ. The state annual PM10 standards is based on studies which show adverse health effects associated with long-term exposure to particles at concentrations of approximately 50 micrograms per cubic meter and higher (ranging from about 50 to 177 micrograms per cubic meter). The state annual standard is also based on a consideration of the lifetime risk of cancer from exposure to the carcinogenic compounds present in PM10. The state annual PM10 standard is approximately equivalent to the previous state annual TSP standard, converted to PM10. In adopting the state annual PM10 standard, the Board relied heavily on the recommendations of the California Department of Health Services.

The national annual PM10 standard is based on studies of respiratory effects and illness in children and adults. The particle concentrations cited in these studies were measured as TSP and were converted to equivalent PM10 concentrations. The conversion used was based on collocated instruments that measured TSP and PM10. The EPA, in setting the national annual PM10 standard, did not consider the carcinogenic potential of long-term exposure to PM10."

Conclusion from this Section

In reality, the TCEQ needs to require CCND to make a significant reduction of more than 50% in its proposed PM10 emissions in order to fully protect public health in the Point Comfort community area. The TCEQ needs to require CCND to submit missing technical information on the daily PM2.5 emissions from diesel locomotives and re-model all particulate emissions. A daily PM10 pollution increase of 10 or more micrograms per cubic meter from the CCND plant will not be acceptable and fails to protect public health.

At a minimum, CCND should be required to use equivalent emission limits, and offsets, as are required for the proposed CPS plant in San Antonio.

2. The application (and projected draft permit) do not require offsets of any pollutant type, with nitrogen oxides, sulfur dioxide and carbon pollution of particular concern.

The draft permit for CPS includes substantial offsets for both nitrogen oxides and sulfur dioxide pollution that will limit the overall emissions of these pollutants to 36 tpy each. These same requirements should be included in CCND draft permit.

Carbon offsets should be required for both plants, as are being required in other states (see Section 7).

3. The projected 1,839 tons of year of total NOx emissions from this plant would affect the ability of the DFW area to come into attainment with the 1-hour and 8-hour ozone standards.

Higher NOx emissions of 1,839 tpy from this plant would cause or contribute to North Texas smog rendering the Dallas SIP ineffective to come into compliance with the federal health-based ozone standards.

The proposed plant site is approximately 275 miles from the Ellis County line, which has been designated non-attainment with the eight-hour ozone standard, and approximately 305 miles to the Dallas County line, which is a county designated as non-attainment for the eight-hour and one-hour ozone standards. Emissions from the Limestone and Big Brown power plants in Central Texas already have been found to affect the DFW areas' air quality (see attachment "a" in March 22, 2004 comments). TCEQ has concluded that "a body of evidence from aircraft measurements, seasonal modeling, back trajectories, and statistical studies indicat[ed] that electric generating facilities and cement kilns in central and eastern Texas contribute to the background levels of NOx which impact the DFW area."

TCEQ has the repsonsiblity to regulate the emissions of NOX that may affect a non attainment area

<u>The Clean Air Act Requires The State To Incorporate Intra-state Air Pollution Transport in All SIPs</u>

The federal Clean Air Act unequivocally mandates that the State consider the effect of any air pollution emissions in the State which might affect a nonattainment area, and include adequate control measures in those upwind areas to timely achieve attainment in all nonattainment areas in the State. Section 107(a) provides:

> Each State shall have the primary responsibility for assuring air quality within the <u>entire geographic area</u> comprising such State by submitting an implementation plan for such State which will specify the manner in which national primary and secondary ambient air quality standards will be achieved and maintained within each air quality control region in such State.

42 U.S.C. § 7407(a) (emphasis added). See also *Train v. NRDC*, 421 U.S. 60, 64 (1975).

Additionally, Section 110(a)(2)(D) requires SIPs to contain "adequate provisions" prohibiting emissions that "contribute significantly to nonattainment in, or maintenance be, any other state." 42 U.S.C. § 7410(a)(2)(D)(i). EPA has formally interpreted this subsection to apply equally to intrastate air pollution transport. 64 Fed. Reg. 14443 (3/25/1999) ("section 110(a)(2)(D)(i)(I) of the Act requires SIPs to prohibit 'consistent with the other provisions of [title I],' emissions which will 'contribute significantly to nonattainment in * * * any other State.' The EPA interprets section 110(a)(2)(A) [required SIP elements] to incorporate the same requirement in the case of intrastate transport.") See, generally, *Michigan v. EPA*, 213 F.3d 663, 672 (D.C.Cir. 2000) (upholding EPA authority under § 110(a)(2)(D) and discretion under the Act itself to control the regional transport of air pollution and ozone precursors).

Significantly, the State has expressly accepted the phenomenon of widespread intrastate transport both in past SIPs (BPA, HGA, DFW) and in the currently pending 5% Increment of Progress Plan for the DFW area. In the latter SIP, the State claimed that air pollution emissions from the Alcoa plant in Rockdale, Milam County, located less than 200 km south of the DFW nonattainment area, contributed to exceedances of the ambient ozone standard, and consequently emissions reductions credit could be claimed as benefiting DFW air quality. See U.S. EPA Guidance on 5% Increment of Progress 40 C.F.R. § 905(a)(1)(ii)(B), August 2004, page 7 (allowing use of reductions from out of the area "only in conjunction with a demonstration that, . . . , the reductions have been shown to impact the nonattainment area."). See generally 69 Fed. Reg. 23951 (4/30/2004).

As a practical matter, were the State to approve significant new emissions of air pollution that could be transported into the DFW or other Texas nonattainment areas through new and modified source permitting actions, the net effect would be to impose additional emissions reductions burdens upon sources in those areas in order for the nonattainment area to demonstrate timely attainment of the 8-hour ozone standard in that area. Preliminary estimates of necessary emissions reductions indicate these emissions reductions will be substantial, and may prove challenging to these areas. It is counter-productive (and illegal) to approve these increases without careful analysis of the consequences of these emissions upon the State's nonattainment areas (including formal nonattainment areas such as DFW, HGA and BPA as well as Early Action Compact areas).

EPA's SIP regulations specifically mandate that SIPs contain specific vehicles to ensure that State permitting of new or modified major sources will not interfere with attainment of a national ambient air quality standard.

40 C.F.R. § 51.160 provides as follows:

(a) Each plan must set forth legally enforceable procedures that enable the State or local agency to determine whether the construction or modification of a facility, building, structure or installation, or combination of these will result in—

(1) A violation of applicable portions of the control strategy; or

(2) Interference with attainment or maintenance of a national standard in the State in which the proposed source (or modification) is located or in a neighboring State.

(b) Such procedures must include means by which the State or local agency responsible for final decisionmaking on an application for approval to construct or modify will prevent such construction or modification if—

(1) It will result in a violation of applicable portions of the control strategy; or

(2) It will interfere with the attainment or maintenance of a national standard.

Thus it is abundantly clear that Texas has a duty to consider and account for new increased emissions, even those that are located outside the nonattainment area, when preparing SIPs.

Texas has a duty to consider the effect of pending permit major source actions on upcoming SIP actions. Texas' decision to include the Alcoa out-of-nonattainment area emissions in the 5% Increment of Progress Plan reflects the State's acknowledgement of intrastate air pollution transport, and its relevance to DFW ambient air quality. Texas must take steps to assure that increased emissions from new and modified major source permitting actions beyond the boundaries of the DFW nonattainment area are considered by and incorporated into the SIP planning process. At the very least, the magnitude of contribution must be quantitatively established and the source of offsetting emissions reductions in DFW be identified and legally secured as enforceable obligations. Implicitly, the DFW emissions reductions necessary to offset the increased emissions must be surplus to the DFW emissions reductions needed for timely attainment of the 8-hour ozone standard. TCEQ itself recognizes that the level of emissions reductions required to demonstrate timely attainment will be substantial, well in excess of the current suite of controls and thus carries an extraordinary burden of evaluation before considering approving any increases in air pollution emissions that will impact DFW. The TCEQ has recognized the impact to the emissions of NOx from existing power plants in East Texas and is proposing significant emissions reductions from existing power plants as a part of its proposed DFW SIP to reduce the NOx background levels.

		Future Year 2009 Emission Projection (TPD)	**Reduction in Tons Per Day (TPD)**	**Estimated Percent Reduction**	**Comments**
21) Electric Generating Facilities - NOx - Apply HGB emission specifications to 9 counties - Apply HGB emission specifications to East Texas (defined by SB7). - Expand existing 4 county DFW NOx controls to 5 new counties.	1999 (TPD) 41.69	2009 (TPD) 11.38[2]	**Reduction in Tons Per Day (TPD)** 30.31	**Estimated Percent Reduction** 72	Low NOx burners, over-fired air, induced flue gas recirculation, Selective Non-Catalytic Reduction (SNCR), Selective Catalytic Reduction (SCR) etc. Further inventory research necessary.

Low NOx burners, over-fired air, induced flue gas recirculation, Selective Non-Catalytic Reduction (SNCR), Selective Catalytic Reduction (SCR) etc.

Further inventory research necessary.

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State Law Empowers TCEQ To Control Excessive Emissions

In addition to TCEQ's responsibilities under federal law, it possesses considerable state law authority and discretion to address the issues surrounding the instant requests for emissions increases before the attainment demonstration SIP process is completed.

The Texas Clean Air Act (TCAA) requires protection of the State's air resources in order to protect public health and safety, general welfare and visibility. TCEQ must undertake vigorous enforcement action against violators.

(a) The policy of this state and the purpose of this chapter are to safeguard the state's air resources from pollution by controlling or abating air pollution and emissions of air contaminants, consistent with the protection of public health, general welfare, and physical property, including the esthetic enjoyment of air resources by the public and the maintenance of adequate visibility.
(b) It is intended that this chapter be vigorously enforced and that violations of this chapter or any rule or order of the Texas Air Control Board [TCEQ] result in expeditious initiation of enforcement actions as provided by this chapter.

Texas Clean Air Act, codified at Texas Health and Safety Code § 382.002.

The TCAA authorizes the Commission to adopt rules more stringent than Federal rules promulgated by the US EPA under the Federal Clean Air Act when the state deems it necessary to protect public health, safety and welfare of its citizens from harmful air pollution. The TCAA serves as the primary authority for Commission review of permits allowing increases in ozone precursor emissions. It both establishes a mandate for TCEQ to ensure that its permitting and SIP actions do not compromise public health and reflects the authority to impose whatever measures are necessary to protect public health.

TCEQ has broad authority under State law to abate nuisances, as do city and county governments.

No person shall discharge from any source whatsoever one or more air contaminants or combinations thereof, in such concentration and of such duration as are or may tend to be injurious to or to adversely affect human health or welfare, animal life, vegetation, or property, or as to interfere with the normal use and enjoyment of animal life, vegetation, or property.

TCEQ General Rule 101.4.

The Texas Health & Safety Code prohibits "Unauthorized Emissions:"

Except as authorized by a board (Commission) rule or order, a person may not cause, suffer, allow, or permit the emission of any air contaminant or the performance of any activity that causes or contributes to, or that will cause or contribute to, air pollution.

Texas Health and Safety Code § 382.085(a).

This authority, individually and collectively, provide TCEQ considerable authority to ensure that excess emissions are not permitted which exacerbate an existing unhealthy air pollution situation, such as currently exists in DFW and other Texas nonattainment areas

What are the effects of transported NOx on ozone in non-attainment areas?
In its recent proposed rulemaking on interstate transport the EPA found that:

Short-term (1- to 3-hour) and prolonged (6- to 8-hour) exposures to ambient ozone have been linked to a number of adverse health effects.

Short-term exposure to ozone can irritate the respiratory system, causing coughing, throat irritation, and chest pain. Ozone can reduce lung function and make it more difficult to breathe deeply. Breathing may become more rapid and shallow than normal, thereby limiting a person's normal activity. Ozone also can aggravate asthma, leading to more asthma attacks that require a doctor's attention and the use of additional medication. Increased hospital admissions and emergency room visits for respiratory problems have been associated with ambient ozone exposures. Longer-term ozone exposure can inflame and damage the lining of the lungs, which may lead to permanent changes in lung tissue and irreversible reductions in lung function. A lower quality of life may result if the inflammation occurs repeatedly over a long time period (such as months, years, a lifetime). People who are particularly susceptible to the effects of ozone include children and adults who are active outdoors, people with respiratory diseases, such as asthma, and people with unusual sensitivity to ozone.

In addition to causing adverse health effects, ozone affects vegetation and ecosystems, leading to reductions in agricultural crop and commercial forest yields; reduced growth and survivability of tree seedlings; and increased plant susceptibility to disease, pests, and other environmental stresses (e.g., harsh weather). In long-lived species, these effects may become evident only after several years or even decades and thus have the potential for long-term adverse impacts on forest ecosystems.

Emissions reductions to eliminate transported pollution are required by the CAA and supported by sound policy. Clean Air Act section 110(a)(2)(D) requires revisions for upwind States to eliminate emissions that contribute significantly to non-attainment downwind. Under section 110(a)(1), these SIP revisions were required in 2000 (three years after the 1997 revision PM2.5 and 8-hour ozone NAAQS); EPA proposes that submitted as expeditiously as practicable, but no later than 18 months after the date of promulgation. There are also strong policy reasons for addressing interstate pollution transport, and for doing so now.

First, emissions from upwind states can alone, or in combination with local emissions, result in air quality levels that exceed the NAAQS and jeopardize the health of citizens in downwind communities. Second, interstate pollution transport requires some consideration of reasonable balance between local and regional controls. Significant contributions of pollution from upwind states go unabated, the downwind area must achieve greater local emissions reductions, thereby incurring extra clean-up costs in the downwind area. Third, requiring reasonable controls for both upwind and local emissions sources should result in achieving air quality standards at a lesser cost than a strategy that relies solely on local controls. For all these reasons, EPA believes it is important to address interstate transport as early as possible. Doing so as we are today, in advance of the time that states must adopt local non-attainment plans will make it easier for states to develop plans to reach attainment of the standards.

It would be inappropriate for the state to ignore the impact of a new source of pollution of this magnitude only 275-300 miles away from non-attainment areas that are required to meet Lowest Achievable Emissions Rate requirements.

4. The BACT analysis performed in the permitting process does not fully explore the best available control technologies.

The proposed plant is located in an area that is designated attainment for all criteria pollutants. Therefore, federal and state law requires that the E.S. Joslin plant must thoroughly evaluate all available control options for these pollutants, to determine emissions limits reflecting the "Best Available Control Technology" for each pollutant to be emitted by the plant.

It has been about 15 years since a new coal plant has been permitted in Texas. Since that time, many new emission control technologies have been developed. We believe that TCEQ staff in approving the City Public Service (CPS) and Sandy Creek Energy draft permits have established BACT limits for new coal fired power plants in Texas and the applicant should be required to meet the same emission rates. As a result, E.S. Joslin should be required to meet the same emissions standards as are proposed for the CPS and SCEA plants.

See the following table comparing emission levels between the CPS and the Sandy Creek and the proposed plant.

emission	Joslin	Sandy Creek	CPS
NOx	0.07	0.05	0.05
SO2	0.1	0.1	0.06
VOC	0.005	0.0036	0.0025

Integrated Gasification Combined Combustion (IGCC) is an effective and affordable technology for the production of electricity from coal. IGCC results in significant reductions in emissions of criteria pollutants, carbon dioxide, and mercury as compared with conventional pulverized coal-fired power plants. IGCC is cost-effective, commercially available on the market and, indeed, is in use at several locations across the country. Texas and federal law requires that all available control technologies be analyzed. The applicant has failed to adequately evaluate IGCC technology. The definitions of BACT under Texas and federal law require that an available alternative technique such as IGCC must be identified and evaluated as a control option in the first step of the BACT analysis. The applicant's failure to do so must be remedied in order to allow a full evaluation of all available control options, as the law requires. Please see the comment of Environmental Defense for a full description of this technology and why it is essential to consider it as part of the BACT analysis.

They chose not to use the process for a number of reasons:
it is a different production process,
it is an innovative fuel combustion technique
it hasn't achieved availability factors that are comparable to pulverized coal.

In a recent decision on the Thoroughbred Generating Company (TGC) for the construction and operation of a 1,500 megawatt (MW) pulverized coal-fired electric generating facility in Muhlenberg County, near Central City, Kentucky the ALJ heard many of the same arguments and found that the State had errored by not requiring the applicant to do a more though review of IGCC technology.

it is a different production process,

This was an argument made in the Thoroughbred case. TheALJ found that the Clean Air Act requires an analysis of the best control for the process of combusting coal, and not just of the type of boiler technology. She found that " a "source" under the PSD program was not the particular boiler the applicant is proposing but instead is the facility the applicant is proposing with the combustion technology subject to change based on a BACT analysis" The ALJ ruled that" The Cabinet's reliance on the definition of "source" as referring to the PC is too narrow and is contrary to the PSD program's focus, which is site oriented, not equipment oriented." She said " I conclude that DAQ erred as a matter of law by concluding that it lacked authority to require TGC to include IGCC and CFB in its BACT analysis."
nor is an innovative fuel combustion technique

This issue was raised in the Thoroughbred case as well. Bill Powers, wtiness for the protestants noted:
"When Senator Huddleston of Kentucky added the term "innovative fuel combustion techniques" to the definition of BACT, he included gasification and fluidized bed combustion in the definition of innovative fuel combustion techniques when he stated:

Mr. HUDDLESTON. Mr. President, the proposed provisions for application of best available control technology to all new major emission sources, although having the admirable intent of achieving consistently clean air through the required use of best controls, if not properly interpreted may deter the use of some of the most effective pollution controls. The definition in the committee bill of best available control technology indicates a consideration for various control strategies by including the phrase "through application of production processes and available methods systems, and techniques, including fuel cleaning or treatment. **And I believe it is likely that the concept of BACT is intended to include such technologies as low Btu gasification and fluidized bed combustion.** But, this intention is not explicitly spelled out, and I am concerned that without clarification, the possibility of misinterpretation would remain. It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account – be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, **gasification**, or liquefaction; use of combustion systems such as **fluidized bed** combustion which specifically reduce emissions and/or the post-combustion treatment of emissions with cleanup equipment like stack scrubbers. The purpose, as I say, is just to be more explicit, to make sure there is no chance of misinterpretation.

95th Congress, 1st Session (Part 1 of 2) June 10, 1977 Clean Air Act Amendments of 1977 A & P 123 Cong. Record S9421 (emphasis added).

it hasn't achieved availability factors that are comparable to pulverized coal
the Eastman IGCC plant in Tennessee has achieved spectacularly high availability rates on its gasification process because it has a spare gasifier. The gasification unit was on line 98% of the time. Thus, the reliability issue is addressed with a spare gasifier, which adds a nominal additional expense. An IGCC unit in Florida has an availability of 88.7% and 84.2% without a spare gasifier, higher than the 75% claimed by TO3

It isn't appropriate for a wholesale power plant since these plants have not demonstrated commercial viability.
IGCC has been demonstrated in practice, in a full scale application, at the time the TO3 permit was applied for. Coal gasification has been operating at Eastman Chemical in Kingsport, TN for since 1983. This underscores that coal gasification is a mature technology. In addition a similar plant shas been operating at Sasol South African for 20 years. IGCC was described by Powers as a cleaner technology than pulverized coal technology, more efficient at burning coal in that it emits less pollution per ton of coal burned and also has an output of more electricity per that ton of coal
The applicants argue that the new plant the new proposed plant is a wholesale power producer. Yet the applicant also argue correctly that the EPA's BACT manual that the cost of technology shouldn't be considered in the decisions about BACT. The also say that there aren't any operating 600 MW IGCC plants and they tend to be smaller units. One advantage to samller units is that they are more modular and can be operated in smaller increments, a real advantage in a compeatvie power market

IGCC has become a process of used by 17 out of 124 new coal plants being permited in the US or 15% of all new applications for coal plants in the US

A feasibility study has shown that siting a mine mouth Lignite fed gasification plant in Texas to produce hydrogen, SNG, electric power, and carbon dioxide could be economically feasible in an era of high natural gas prices.

Production of electric power from these conceptual co-production plants provides a valuable revenue stream.. It was assumed that these plants would be base load and that the value of the electricity was $35.6/MWH. . He further assumed that their was significant value from the sale of by product gasses such as carbon and hydrogen.

5. The application (and projected draft permit) do not utilize best available control technologies for sulfur pollution as established by an application filed prior to this one for the City Public Service plant in San Antonio.

The draft permit for CPS calls for use of wet flue gas desulfurization for sulfur emissions as BACT. The draft CCND application suggests that the TCEQ deemed it acceptable to allow for the use of a less effective technology, dry flue gas desulfurization (FGD), resulting in a 20% greater sulfur limit from the CCND plant. The Point Comfort community may be impacted in the same way due to excessive sulfur pollution.

6. Due to concerns for visibility in Class I areas such as Big Bend National Park, 100% of SO2 and NOx pollution from the new plant should be offset with reductions at other facilities within the Central and South Texas Region.

This plant will impact visibility at Big Bend National Park, a Class I area. The Regional Haze rule is meant to regulate all plants that contribute to regional haze in Class I areas. Modeling conducted for the BRAVO study has shown that visibility in Big Bend National Park is in fact impaired by plants that are much farther away than Calhoun County .

Due to concerns for non-attainment and health issues as well as visibility in Class I areas such as Big Bend National Park, 100% of SO2 and NOx pollution from the new plant should be offset with reductions at other facilities.

At least one other utility (Xcel in Colorado) is offering its customers a much better package with its proposed new Comanche 3 coal plant. This package includes substantial overall pollution reductions and much more serious investments in wind power and energy efficiency.

This plant will impact visibility at Big Bend National Park, a Class I area. The Regional Haze rule is meant to regulate all plants that contribute to regional haze in Class I areas. Modeling conducted for the BRAVO study has shown that visibility in Big Bend National Park is in fact impaired by plants that are much farther away than Point Comfort.

7. The application (and projected draft permit) do not examine the opportunies for obtaining sulfur and mercury emissions reductions through coal washing

The application (and projected draft permit) do not consider coal washing options as BACT which should reduce sulfur and other harmful emissions regulated by the TCEQ. The TCEQ has the authority and the responsibility to better regulate harmful gases and particulate matter and must do so.

8. The application (and projected draft permit) do not examine the opportunities to reduce emissions by using lower emissions fuels

The application (and projected draft permit) do not address clean coal options which clearly should be able to reduce sulfur and related emissions by the TCEQ. The TCEQ has the authority and the responsibility to regulate harmful gases and particulate matter and must do so. CCND did not appear to represent whether they would be utilizing high sulfur dirty coals or low sulfur less dirty coals, but the TCEQ needs to require clear representations on the type of coal and require low sulfur, less dirty coals as options under the BACT determination.

9. The draft permit does not address global warming gases which clearly should be regulated by the TCEQ.

The TCEQ must consider carbon dioxide emissions in regulatory decisions.

Our organizations request that the TCEQ require CCND to offset 100% of emissions of global warming gases from this plant. Other states have recognized the impact of power plant carbon emissions on their environment and have taken aggressive regulatory action including offsetting requirements. Texas, the greatest contributor to global warming gases in the U.S., owes it to the citizens of Texas to follow suit.

The most objective, well-respected source on global warming is the Intergovernmental Panel on Climate Change (IPCC), which has issued reports on global warming in 1990, 1995, and 2001. The most recent report included 2,600 pages compiling the voluminous evidence pointing toward human responsibility for climate change. With 122 main authors, 515 contributing authors, and another 450 scientists from all over the world who reviewed the report before it was published, the IPCC reports can hardly be dismissed and the conclusions regarding humankind's role in warming the atmosphere have been stronger with each study. In its most recent (2001) report, the IPCC estimated that surface temperatures could rise up to 10.4 degrees F over this century, and sea levels could rise nearly three feet.

Evidence that the earth is undergoing a dangerous warming trend becomes more glaring with each year. Nineteen of the hottest twenty years ever measured have all occurred since 1980. The warmest year measured to date was 1998; the second and third warmest were 2002 and 2003. Not coincidentally, the amount of CO_2 in the atmosphere has been found to be at its highest level in every successive year. From a baseline of 280 parts per million (ppm) before the industrial revolution, as of March 2004, the CO_2 concentration was measured at 379 ppm. Even more alarming, CO_2 concentrations are building up faster than ever. As more of the world industrializes, we are seeing carbon concentrations rise accordingly. The atmospheric CO_2 concentration is now increasing by about 3 ppm annually, versus about 1 ppm annually in the middle of the twentieth century.

Global warming and the pollutants that lead to global warming must be considered in the BACT analysis. Global warming will likely be the most pressing environmental and public health concern of our time. Even the Pentagon has recognized global warming as a serious threat. A 2004 report from the Pentagon synthesized some of the recent findings in the area of rapid climate change, warning of the possibility of global famine and wars over shrinking resources, and urging that global warming be raised "beyond a scientific debate to a national security concern."

Heat waves that have occurred in recent years and may have been associated with global warming have already resulted in tens of thousands of deaths.

Ozone/Pollution

Global warming imperils Texans' health by altering the composition of the air we breathe. The higher CO2 levels observed today do not pose a direct threat to human health, but their indirect effects are severe. For one, temperatures above 90°F can produce more ozone, a leading component of smog. Ozone has been shown to damage lung tissue, particularly among children and the elderly. This is of particular concern in San Antonio where ozone pollution may soon exceed EPA's health-based 8-hour ozone standard. Higher temperatures will also cause increased energy use and burning of fossil fuels in warm climates such as Texas as people increase their use of air conditioning. The hotter summers predicted by IPCC and most other climate scientists will have a significant impact on Texas, which already experiences a high number of days over 90 degrees.

Floods

Floods are projected to increase in frequency and severity, as shown through the recent misfortune of the city of San Antonio. In October, 1998, San Antonio was subjected to 11 inches of rainfall in 1 day—twice as much as the city had ever received in a day. Ultimately, the flood of 1998 killed 31 residents of San Antonio and caused over $750 million in property damages. The city was hit by a second destructive flood in 2002, as was much of the rest of Texas. Both the 1998 and the 2002 floods were events of a magnitude that should be projected to occur only once every 500 years. And since 1998 we've had a 250 year flood as well. Two "500-year" floods in a four-year period are unlikely to simply be a coincidence. Statewide, the 2002 flood caused over $1 billion in damages to 41 Texas counties. Furthermore, as many Texans are aware, floods cause damage even after the flood is over. Molds and fungi, including stachybotrys chartarum or "black mold" can grow inside buildings long after floodwaters have receded. It appears that the consequences of unchecked global warming will likely include both extreme weather and extreme financial burdens.

Drought

A study by the World Meteorological Association found that the 1990s had been the hottest decade in 1000 years. The present decade is projected to be even warmer, and Texas is likely to experience a greater frequency and severity of droughts. In fact, based on droughts observed in recent years, what now seems like an unusual period of lack of rainfall may before long come to be viewed as the norm. The 1999-2002 drought was one of the three most extensive droughts in the last 40 years. The summer of 2002 was the nation's hottest since the "Dust Bowl" era of the 1930s. Locally, the period from April through June of 1998 was the driest three-month period in 104 years for Texas, as well as for Louisiana and Florida. Warmer temperatures will cause increased evaporation and exacerbate problems of water scarcity for many Texans.

The National Assessment of Climate Change examined increasing evaporation of Texas' water resources around the San Antonio Edwards Aquifer region. This study found that the area would suffer reduced spring flows, less irrigation, and a regional welfare loss of $2.2-$6.8 million per year due to global warming. Spring flows at Comal springs were shown to decrease by 10-16% by 2030 and 20-24% by 2090. Consequently, as water resources are diverted from agricultural use, farm income is projected to fall from 16-30% by 2030 and 30-45% by 2090. Longer droughts also mean that Texas can expect to share the problem of increased wildfires that it western neighbors are experiencing. In 2002, the western United States experienced its second worst wildfire season in the last 50 years, with over 7 million acres being burned. Oregon, Arizona, and Colorado had their worst wildfire seasons ever recorded.

Disease and Pests

Another health risk global warming poses for Texas is that warming weather is projected to be favorable to the spread of pests, including some species not indigenous to the state which will migrate north as the climate changes. The West Nile Virus, for instance, has succeeded in spreading beyond its original tropical home partly because the climate of the U.S.'s southernmost states are gradually becoming more suitable for disease-bearing mosquitoes and other invasive tropical species. Many insects indigenous to the state will likely flourish as well, because freezing winter temperatures which naturally control bug populations will be less frequent. In this context, the reappearance of dengue fever in Laredo is one more troubling sign that global warming has already begun to affect the health of Texans.

Species Extinction

Elevated global temperatures will put numerous species at risk, as organisms are forced to abandon ecosystems they may have spent thousands of generations specifically adapting to. Camille Parmesan, a biologist at the University of Texas, has found that numerous species already are moving northward due to rising temperatures. As a result, they push many endangered species further toward extinction. The number of species at risk for extinction due to global warming is alarmingly high, and some already appear to have succumbed to the sudden transformation of their native habitat by rising temperatures. According to a 2004 study published in the Nature, up to 37% of 1,103 species studied could face extinction or near-extinction as a consequence of global warming.

Rising Sea Levels/Melting Ice Caps

One of the greatest impacts global warming is projected to have in Texas is that warmer temperatures will trigger a rise in sea levels. Warmer temperatures raise sea levels in two ways: by releasing frozen water stored in glaciers and ice sheets into the world's oceans, and because warmer water takes up more volume. According to the latest estimate from the IPCC, sea levels could rise nearly three feet by the end of the century. A rise of this magnitude would be devastating to Texas' coastal communities, especially when considering that subsidence already causes many coastal areas to slowly sink under their own weight, which makes the relative sea level rise even higher. In addition to property losses on the part of beachfront property owners, rising sea levels will also reduce the amount of public beach land available to Texans. Higher sea levels also pose a danger to coastal aquifers, which could face intrusion by saltwater into sources of agricultural and drinking water. Any of these possibilities would have a devastating effect on the state budget as well. For instance, the cost of sand replenishment to protect coastal Texas from just a 20-inch sea level rise by 2100 is estimated at $4.2-$12.8 billion. If carbon reduction measures are not taken, the Gulf coast of Texas is projected to lose 500 square miles of its shoreline as sea levels rise. Former land commissioner Garry Mauro has illustrated this by comparing it to "a modern-day Paul Bunyan with a chainsaw cutting one-and-a-half miles off the Texas coast all the way from Port Arthur to the Rio Grande."

An increasing number of climate scientists are taking seriously the notion that climate change may occur more rapidly than previously assumed. Instead of a steady deterioration over centuries, the earth's climate may experience a "positive-feedback loop" in which natural processes associated with warming temperatures mutually reinforce one another and accelerate the warming trend. As one example, warmer temperatures would melt more of the earth's ice sheets, which would expose the darker, heat-absorbing surface under the ice sheets, which would cause an accelerated temperature rise that would melt the remaining ice faster. Paleoclimate data suggest that this has happened in the past. Likewise, as CO2-influenced warming causes permafrost in tundra regions to thaw, the exposed permafrost releases some of its own frozen carbon back into the atmosphere and speeds up the process. Another scenario for rapid climate change which is disputed by some climate scientists but gaining popularity is the possibility that the "thermohaline circulation" of the ocean—the transfer of tropical waters to warm the cooler North Atlantic—can be disrupted or even shut down as melting ice packs dilute ocean water salinity and thus prevent it from circulating normally. Recent climate studies show that, 8,200 and 12,700 years ago, a period of gradual warming was followed by abrupt cooling—up to 5 degrees per decade.

Insurance

A less-understood aspect of the economic costs of climate change is how global warming will raise—and likely already is raising—Texans' insurance rates. Insurance companies are taking the threats of global warming seriously and must adjust their rates accordingly. The world's largest reinsurer, the Munich Re Group, called the unusually hot summer of 2003 "the summer of the future," in the sense that it expects global warming to keep temperatures climbing in the years ahead. The reinsurance group also indicated that the "increased risk and losses" due to rising temperatures "means adjustments in premiums." For Texans, who already pay the highest home insurance rates in the country, this is unwelcome news.

The insurance industry has abundant reasons to raise premiums based on risk factors associated with global warming. On a decade-by-decade basis, storms causing in excess of $5 million in insured losses nationwide have increased from 10 in the 1950s to 35 in the 1990s. These catastrophes have grown from about $100 million annually in the 1950s to $6 billion per year in the 1990s. Insurance losses from extreme weather events for the United States went from $2 billion per year in the 1980s to $12 billion per year in the 1990s. Ultimately, global warming already is imposing real financial costs on consumers.

Other states are regulating and requiring offsets of global warming emissions.

The states of Oregon, Maine, New Hampshire, New Jersey and Massachusetts have passed laws that mandate the reduction or mitigation of greenhouse gas emissions from power plants. In some of these states, new power plants must mitigate carbon emissions that rise above state limits. In addition to individual state initiatives, some states are banning together to demand that the EPA regulate carbon dioxide emissions.
Oregon has stipulated that new plant applicants must offset 17% of the emissions of any new power plant. They can also buy credits from the climate trust.
Maine has mandated a reduction of greenhouse gas emissions from power plants to 1990 levels by 2010 and reduction of 10% more by 2020. Maine aims to reduce its CO_2 emissions by 75-80% over the long term.
The State of New Hampshire has legislated a cap on greenhouse gas emissions. The state decided on a CO_2 emissions cap because "a high quality-of-life environment has been, and will continue to be, essential to New Hampshire's economic well-being. [Protecting] New Hampshire's high quality-of-life environment by reducing air pollutant emissions returns substantial economic benefit to the state through avoided health care costs; greater tourism resulting from healthier lakes and improved vistas; more visits by fishermen, hunters, and wildlife viewers to wildlife ecosystems, and a more productive forest and agricultural sector."
Massachusetts imposed additional regulations on its 6 dirtiest power plants in June 2001, which require the plants to reduce CO_2 emissions by 10% from 1997-99 average levels.
New Jersey reached a voluntary agreement with its public utility to reduce CO_2 by 15% below 1990 levels.
New York State facilities were ordered by Governor Pataki to reduce energy consumption 35% below 1990 levels by 2010.
12 Northeastern states have set a goal of reducing energy sector CO_2 by 20%

below 2001 levels by 2025.
Attorney Generals from Maine, Massachusetts and Connecticut have sued the EPA, arguing that the EPA has a mandatory duty to regulate carbon dioxide emissions under the Clean Air Act. According to the Attorney Generals, by violating Section 304(a)(2) of the Clean Air Act, 42 U.S.C. 7604(a)(2), EPA is unlawfully increasing the likelihood of harming the economic interests of the Plaintiff States, is unlawfully increasing the likelihood and severity of damage to property owned by each of the Plaintiff States, is unlawfully denying residents of each of the Plaintiff States the benefits due them under the federal Clean Air Act, and is unlawfully subjugating residents of each of the Plaintiff States to increased risks of harm to human health, welfare, and general economy that is associated with the continued unregulated emissions of carbon dioxide.
Subsequently, on October 23, 2003, twelve state Attorney Generals filed a separate lawsuit against the EPA for failing to regulate CO2 emissions. The Attorney Generals were compelled to act because they viewed unregulated carbon dioxide as an unacceptable danger to the public health, economies, and natural resources of their states.
Austin Energy and four other electric power companies from across the United States answered a challenge from the World Wildlife Fund to become the first U.S. power companies to support a mandatory cap on carbon dioxide emissions and confirm their commitment to clean energy. By switching to clean renewable energy and increasing energy efficiency through innovative technologies and processes, each of these five power companies – Austin Energy, Burlington Electric Department, FPL Group, Inc., Sacramento Municipal Utility District, and Waverly Light and Power – will significantly reduce CO2 emissions. The power companies have agreed to support binding limits on national CO2 emissions and undertake one or more of the following action targets: renewables as the source for 20 percent of their electricity sold by 2020, or increase energy efficiency by 15 percent by 2020, or retire the least efficient half of coal generation by 2020.

Carbon dioxide fits Texas' definition of an air contaminant.

It is state policy "to safeguard the state's air resources from pollution by controlling or abating air pollution and emissions of air contaminants." CO2 fits the definition of an air contaminant as defined in Section 382.003, affects Texas health in many ways including impacts on ozone formation. In the last several years, we have seen numerous states take aggressive action to curb CO2 emissions from power plants. New Hampshire, Oregon, Massachusetts, Maine, Washington, New York and others have mandated restrictions on new power plant carbon emissions. For lack of a New Source Performance Standard for CO2, these restrictions should be considered a BACT floor for CO2 emission reductions from the CPS facility.

In TCEQs January 2002 report of greenhouse gas emissions it is recommended that Texas should "expand and actively promote the use of clean and renewable energy resources, and carbon sequestration." Additionally, it stressed the importance that Texas "actively promote and expand" energy efficiency and conservation programs.

The Kyoto treaty will soon become international law. Though the U.S. has not signed onto this treaty, we may be forced to comply or face trade sanctions. In the future, power plants are projected to pay around $25 per ton for carbon reductions. If applied to all carbon emissions from this new plant hat would mean an additional $200 million in fees per year.

When carbon becomes regulated, CCND will be forced to purchase carbon reductions, because they can't plant enough trees to offset their emissions. An urban forest big enough to offset the carbon emissions would stretch from San Marcos to Hondo and from Comfort to Falls City; an area eleven times larger than San Antonio.

The proposed CCND plant would single-handedly raise Texas' coal-combustion greenhouse gas emissions by about 5% and carbon control strategies are cost effective. Thus, we have arrived at a critical moment when the TCEQ must begin to regulate carbon dioxide and require offsets and reductions of this air contaminant.

Our organizations and the members we represent urge the commission to follow its own recommendations and take unambiguous steps to "actively promote" healthier energy alternatives, by requiring the permit applicant to offset its greenhouse gas emissions through energy efficiency and other cleaner methods of generating power that do not contribute to carbon pollution.

The TCEQ has authorized the use of energy efficiency and renewable energy as valid control measures for reducing criteria pollutants.

The TCEQ has recognized energy efficiency and renewable energy projects as valid emissions reductions measures in State Implementation Plans to meet federal National Ambient Air Quality Standards. The Commission allows political subdivisions required to report to the State Energy Conservation Office under Section 388.005 of SB5 to report energy savings from energy efficiency and renewable energy projects for inclusion in their local SIP. On December 13, 2001 the TCEQ revised the Houston-Galveston SIP to include a protocol for implementing and calculating pollution reductions from energy savings resulting from Senate Bill 5 and Senate Bill 7 measures. This revision was followed by a revision to the Dallas-Fort Worth SIP on March 5, 2003, which included an estimate of NOx reductions associated with SB5 and SB7.

In its 2001 amendments to the Texas Clean Air Act designed to end grandfathering, the Legislature authorized the use of wind, biomass, and solar energy as alternatives to top of the stack pollution controls. By doing so we believe that they established these alternatives as measures that should be evaluated as control strategies and thus used in a BACT analysis.

382.05193. Emissions Permits through Emissions Reduction

(b) The commission by rule shall establish a program to grant emissions reduction credits to a facility if the owner or operator conducts an emissions reduction project to offset the facility's excessive emissions. To be eligible for a credit to offset a facility's emissions, the emissions reduction project must reduce emissions in the airshed, as defined by commission rule, in which the facility is located.

(c) The commission by rule shall provide that an emissions reduction project must reduce net emissions from one or more sources in this state in an amount and type sufficient to prevent air pollution to a degree comparable to the amount of the reduction in the facility's emissions that would be necessary to meet the permit requirement. Qualifying emissions reduction projects must include:

(1) generation of electric energy by a low-emission method, including:
(A) wind power;
(B) biomass gasification power; and
(C) solar power;
(2) the purchase and destruction of high-emission automobiles or other mobile sources;
(3) the reduction of emissions from a permitted facility that emits air contaminants to a level significantly below the levels necessary to comply with the facility's permit;
(4) a carpooling or alternative transportation program for the owner's or operator's employees;
(5) a telecommuting program for the owner's or operator's employees; and
(6) conversion of a motor vehicle fleet operated by the owner or operator to a low-sulfur fuel or an alternative fuel approved by the commission.

A valid BACT analysis should consider all environmental, health and economic impacts including cost of health damage to our children from mercury pollution, the public health and environmental impacts of global warming including flood related deaths, and the future cost of purchasing carbon credits for this new plant. A true economic analysis would also consider that energy efficiency investments bring jobs to San Antonio and put money back into consumers' pockets in the form of energy savings whereas a coal plant will drain consumers pockets and send their money to Wyoming in coal purchases to fuel the plant.

The TCEQ has recognized the need to reduce carbon pollution and the use of energy efficiency and renewable energy as valid control measures for reducing carbon pollution.

The TCEQ stated in its January 2002 report of greenhouse gas emissions, that

Texas should "expand and actively promote the use of clean and renewable energy resources, and carbon sequestration." Additionally, it stressed the importance that Texas "actively promote and expand" energy efficiency and conservation programs.

We urge the commission to follow its own recommendations and take unambiguous steps to "actively promote" healthier energy alternatives, by requiring the permit applicant to consider alternatives to the project that don't emit greenhouse gases and to offset 100% of any global warming gas emissions released through this project.

11. The draft permit does not adequately manage fugitive emissions either from coal and ash handling or during start-up and shutdown.

The applicants propose using a variety of control devices on their coal and ash handling equipment, however, they will still emit a significant amount of particles. These emissions will clearly impact the health and safety of those living downwind.

12. The draft permit is not clear on the mercury emissions that will come from this plant.

The application information gives a numerical mercury limit of 2 x 10-6 lb/MWh but under Special Conditions it lists that the facility will comply with the mercury MACT as adopted, and under Special Conditions it also states that the mercury limit will not exceed 2 x 10-5 lb/MWh. The draft permit should clearly require carbon sorbent injection with emissions not to exceed 2 x 10-6 lb/MWh, as proposed by the applicant. It should specify in the permit that f and when the currently proposed federal mercury rule comes into effect, CCND will not be allowed to purchase mercury credits to meet their emission limit.

Calhoun County Navigation District's Energy Station (CCND) would be allowed to emit up to 60 lbs of mercury annually into the air from this new plant even though eleven lakes and the entire Gulf of Mexico have mercury levels so high that pregnant women are warned not to eat the fish. The new CCND plant is particularly close to Lavaca Bay already contaminated with mercury. A recent study by University of Texas has associated a 17% increase in autism rates with every 1000 lbs of mercury pollution.

Human exposure to mercury occurs primarily through eating contaminated fish. Exposure to high levels of mercury has been associated with serious neurological and developmental effects in humans. In 2000, the National Research Council of the National Academy of Science described the potential adverse health effects of consuming methyl mercury (either directly, or in the case of a developing fetus, through the mother's blood supply) in amounts above the reference dose (a safe consumption level, of 0.1 micrograms per kilogram of body weight per day.) These effects include neurological and developmental problems such as poor attention span and delayed language development, impaired memory and vision, problems processing information, and impaired fine motor coordination. Because the developing fetus is the most sensitive to the effects from methyl mercury, women of child-bearing age are regarded as the population of greatest interest.

Once mercury enters waters, either directly or through air deposition, it can bioaccumulate in fish and animal tissue in its most toxic form, methyl mercury. Bioaccumulation means that the concentration of mercury in predators at the top of the food web (for example, predatory fish and fish-eating birds and mammals) can be thousands or even millions of times greater than the concentrations of mercury found in the water.

Mercury emissions from coal-fired power plants can be dramatically and affordably reduced from all types of existing boilers burning all types of coals. Many research organizations, federal agencies, technology vendors and power companies have accelerated efforts to develop and demonstrate cost-effective mercury control technologies that can be implemented by power plants. The technical capability to control mercury is already here and commercialization of new technologies is already beginning in anticipation of new federal emission standards. However, CCND has failed to follow the BACT analysis standard and to examine cost effective control technologies. We urge the TCEQ to require such an analysis.

In April of 2001, the John Steiz, then the head of the Office of Air Quality Planning and Standards for EPA, sent a letter to the regional administrators reviewing EPA's policy on mercury controls. It read in part:

On December 14, 2000, the EPA announced that it was adding coal- and oil-fired power plants to the section 112(c) list of sources (65 FR 79825; December 20, 2000). Therefore, each coal-fired or oil-fired electric utility steam-generating unit which is constructed or reconstructed will now be subject to the case-by-case provisions of the Act until the EPA promulgates a nationally applicable MACT standard to address hazardous air pollutants for this source category.

For approximately four years, EPA has given the regulated community clear signals that it would propose 90% reduction in mercury from power plants. However, on March 15, 2005, EPA finalized a mercury rule that set national limits on mercury from power plants and allows a cap-and-trade regulatory method that could be very harmful to public health. Thus the 90% reductions that we were to get under the Clean Air Act will not come to pass. Given the amount of controversy, it is reasonable to expect that litigation will occur, delaying final implementation of these rules for years.

Thus, until such time that all litigation is settled, the April 2000 memo makes it clear that utilities must do thorough case by case analysis.

See comments previously submitted by Public Citizen on CCND's application for more information on available controls for mercury emissions.

13. The TCEQ must implement baseline ambient air monitoring in Point Comfort, Texas.

Point Comfort residents have been collecting disconcerting information about harmful health effects and private property damage from residents of southeast San Antonio living in the area of the City Public Service's electric utility plants in the Calaveras Lake vicinity. What we have learned about the health and property damage complaints of the southeast San Antonio residents to date is deeply discouraging to say the least. We now know to reasonably expect that many in the Point Comfort community will likely suffer adverse health effects and property damage from CCND's plant due to its proximity to populated communities. Point Comfort residents may consequently join the San Antonio residents in suffering from health and property impacts once the Calhoun County Navigation District plant is built unless the agency seeks to require greater reductions and issues a more stringent permit for a much lower emitting, cleaner power plant.

Point Comfort residents are concerned that the Calhoun County Navigation District's plant is being sited directly adjacent to our community and homes-- too close for such a dirty, pulverized coal-fired electric utility power plant.

We want to express the following community concerns about the localized heavy pollution fallout from the proposed Calhoun County Navigation District Energy plant:

* adverse human health consequences suffered by Point Comfort-Victoria residents and children

* adverse animal health consequences caused to our farm animals and pets

* private property damage from acid rain and acid dust fallout we know will occur from acidic chemicals emitted by the Point Comfort plant

* ground level fugitive coal dust blowing off the plant's coal stockpiles onto our property if not properly watered and adequately controlled

* bioaccumulation of mercury and highly toxic chemicals emitted by the plant, since EPA recognizes unusually harmful substances which are persistent, toxic and bioaccumulative.

We are formally requesting that the TCEQ require, as part of the Calhoun County Navigation District plant's permit, ambient air pollution monitoring beyond the fence line in the Point Comfort community to provide a real-world level of evidence to support that the Calhoun County Navigation District electric utility is not polluting at unsafe levels or otherwise harming the community. So far we have not seen any community air monitoring proposed in the other draft permits for new coal-fired power plants and that is projected to be a serious public health concern in the projected draft Calhoun County Navigation District permit and feel strongly that the agency is erring in not requiring this kind of added safeguard, particularly since such monitoring technology is readily available today. We request a local ambient air monitoring system to be set up and an air monitoring protocol to be designed to help resolve specific concerns of unsafe pollution from the CCND power plant.

We ask that the monitoring system test for: sulfur dioxide, particulate matter 2.5 & 10 microns, nitrogen oxides, carbon monoxide, hydrochloric acid & other acidic chemicals like sulfuric acid along with other toxins that the Point Comfort community could be reasonably projected to be concerned about.

We request that ozone monitoring should be conducted. High levels of nitrogen oxide emissions from the power plant during peak operations coupled with high background pollution particularly in the hot summer months of July, August and September may contribute to higher ozone levels in our area and potentially push Point Comfort and Victoria into exceeding the federal eight-hour ozone standard. In terms of the ambient air monitoring, we request either the agency conduct the monitoring or the company pay 100% for the Point Comfort monitoring station. We request the following monitoring occur:

Baseline ambient air testing needs to be conducted at least six months before the Calhoun County Navigation District plant starts operations.

After plant startup, real-time testing of the plant pollutants listed above.

Meteorological data such as wind speed, wind direction, and related variables.

Provide the public with real-time online access to the pollutant monitoring data to allow the Point Comfort community to help us in tracking the plant's compliance and to find out how the plant is operating if we experience air pollution problems associated with its electric utility operations.

In addition, we request a mercury sampling and testing program to test locally caught fish in local stock ponds and other area water bodies as necessary to determine the Point Comfort-Victoria community impacts of mercury from the Calhoun County Navigation District Energy Station:
Baseline mercury testing to determine background levels before the plant starts operations. Upon plant startup, implement a comprehensive mercury fish monitoring program including sampling and testing in the Point Comfort-Victoria-Lavaca Bay area.

If the TCEQ does not possess the funding necessary to carry out the requested community air monitoring and fish testing, then the agency needs to require Calhoun County Navigation District to pay for all the necessary community testing as part of the permit or through other arrangements or agreements.

14. The application (and projected draft permit) do not include the diesel and particulate pollution that will result from the rail line that would bring coal to this plant.

As part of this project, a new rail car line may be needed to come into Point Comfort to bring coal to the new plant. This will result in diesel emissions of NOx and particulates from the train as well as coal particulate emissions from the rail cars.

Diesel particulate emissions have been found to pose 7 times the cancer risk of all other air toxics combined. These emissions are part of this project and should be included in the air emission permit for the proposed plant.

Diesel air pollution is one of the most common toxic air pollutants. A broad range of chronic, adverse health effects are associated with diesel exhaust exposure, including exposures at relatively low levels. Diesel emissions include oxides of nitrogen, sulfur oxides, harmful heavy metals, particulate matter (containing many Polycyclic Aromatic Hydrocarbons) and numerous recognized human carcinogens. CCND seeks permission to emit more 1,480 tons per year of PM10, including a large fraction of PM2.5 sized fine particles which are more toxic and more deadly than the slightly larger PM10 particles. PM2.5 fine particulate matter is loaded with toxic substances, particularly Polycyclic Aromatic Hydrocarbons such as benzo(a)pyrene. But the Calhoun County Navigation District's Plant will have additional sources of Polycyclic Aromatic Hydrocarbons and PM2.5 from the diesel-burning trains carrying coal to the Point Comfort plant.

Diesel air pollution, such as the emissions coming from the trains traveling daily to the Calhoun County Navigation District Power Plant, is highly toxic and carcinogenic due primarily to the presence of Polycyclic Aromatic Hydrocarbons. Polycyclic Aromatic Hydrocarbons (PAHs) are a group of chemicals that are formed during the incomplete burning of coal, oil, gas, wood, garbage, or other substances. There are more than 100 different PAHs. In the environment, you are most likely to be exposed to PAH vapors or PAHs that are attached to dust and other particles in the air. Sources include cigarette smoke, vehicle exhausts, asphalt roads, coal, coal tar, wildfires, agricultural burning, residential wood burning, municipal and industrial waste incineration, and hazardous waste sites. EPA and others have determined that Dibenz[a]anthracene is the most toxic PAH, with a Toxicity Equilvalency Factor (TEF) of 5; and Benzo[a]pyrene, the next most toxic with a TEF of 1. Particle-bound PAHs can be transported long distances and removed from the atmosphere through precipitation and dry

deposition,
Examples of PAHs include:

CAS No.	Chemical	Carcinogenic status
56-55-3	Benz[a]anthracene	Reasonably Anticipated Carcinogen, Known to cause cancer
205-99-2	Benzo[b]fluoranthene	Reasonably Anticipated Carcinogen Known to cause cancer
205-82-3	Benzo[j]fluoranthene	Reasonably Anticipated Carcinogen Known to cause cancer
207-08-9	Benzo[k]fluoranthene	Reasonably Anticipated Carcinogen Known to cause cancer
50-32-8	Benzo[a]pyrene	Reasonably Anticipated Carcinogen Known to cause cancer
218-01-9	Chrysene	Known to cause cancer
226-36-8	Dibenz[a,h]acridine	Reasonably Anticipated Carcinogen Known to cause cancer
224-42-0	Dibenz[a,j]acridine	Reasonably Anticipated Carcinogen Known to cause cancer
53-70-3	Dibenz[a,h]anthracene	Reasonably Anticipated Carcinogen Known to cause cancer
194-59-2	7H-Dibenzo[c,g]carbazole	Reasonably Anticipated Carcinogen Known to cause cancer
192-65-4	Dibenzo[a,e]pyrene	Reasonably Anticipated Carcinogen Known to cause cancer
189-64-0	Dibenzo[a,h]pyrene	Reasonably Anticipated Carcinogen Known to cause cancer
189-55-9	Dibenzo[a,i]pyrene	Reasonably Anticipated Carcinogen Known to cause cancer
191-30-0	Dibenzo[a,l]pyrene	Reasonably Anticipated Carcinogen Known to cause cancer

57-97-6 7,12-Dimethylbenz(a)anthracene Known to cause cancer

193-39-5 Indeno [1,2,3-cd]pyrene Reasonably Anticipated Carcinogen Known to cause cancer

3697-24-3 5-Methylchrysene Reasonably Anticipated Carcinogen Known to cause cancer

An EPA study released in 2002 stated that exposure to diesel exhaust can cause cancer.

The Environmental Protection Agency concluded that long-term exposure to exhaust from diesel engines likely causes lung cancer in humans and triggers a variety of other lung and respiratory illnesses. The EPA's 651-page diesel health assessment report cited occupational health studies and tests on animals showing diesel emissions to be a carcinogen, or cancer-causing substance.

15. Air toxics that would come from this plant are not adequately addressed. The toxicology review also does not address short-term SO2 spikes.

The Health Effects review performed for this project states that the health of the public will not be impacted by this project even though the ESLs for both silica, a known carcinogen, and lime are exceeded.

The ground level concentration and exposure to the public to silica exceeds the long term ESL by three fold. The short term ESL for lime is also exceeded.

The toxicology report as included in the draft permit is not adequate to determine health effects to the public. Our organizations request that the TCEQ release a full toxicological study with data that is presented in a way that the public can easily see whether there is no harm posed by this project.

In addition to these issues with the Health Effects Review, neither TCEQ nor CPS have addressed the potential for adverse public health effects related to 5-minute SO2 exposures. TCEQ does not normally go less than 30-minute exposures in reviewing maximum SO2 ground level concentrations (GLCmax).

Short-term exposures to high SO2 concentrations could result from spiked emission events lasting less than one-hour coupled with bad meteorological conditions such as inversions and/or low wind speed conditions; these do occur in San Antonio and are associated with high ozone days. CPS will have high SO2 emissions during hot summer days and cold winter days due to high electric demands.

Follows is an exerpt from a letter written by Bob Yuhnke, an attorney and consultant for the Group Against Smog and Pollution (GASP) in Pittsburgh. This letter was submitted to Roger C. Westman, Air Quality Program Manager of the Allegheny County Health Department, on May 21, 1999. In this letter, Mr. Yuhnke raises the issue of health effects from short-term exposures to SO2 from a coke plant. Mr. Yuhnke's citations are in italics.

"Evaluating for Health Effects Attributed to Five-minute Concentrations of SO2.

The second pollutant exposure of concern is short-term peak concentrations of SO2 which are not prevented by the 1971 annual and 24-hour NAAQS for SO2. In EPA's review of the SO2 NAAQS in 1996, EPA found that five-minute peaks *0.6ppm "should be regarded as significant from a public health standpoint." *61 Fed. Reg. 25,573.* GASP asks that you use that exposure limit as one of the criteria for determining whether SO2 emissions from the proposed modified Shenango coke plant will endanger the public health and welfare under §2101.11. 1.

Evidence of Health Hazard for Exposure to Five-minute SO2 Peaks.
EPA's conclusion regarding the health significance of these exposures relies heavily on an analysis of nearly 40 controlled exposure studies performed by a number of investigators who measured changes in lung function and observed the symptoms experienced by mild and moderate asthmatics exposed to known concentrations of SO2 in the laboratory that replicate measured concentrations of SO2 found in the ambient air near sources of SO2. These studies demonstrate an approximate dose/response relationship between the concentration of SO2 inhaled and the effects experienced by asthmatic subjects. Participants in the studies experienced a wide range of reactions, e.g., 10 to 25% of mild or moderate asthmatic individuals exposed to 0.2 to 0.5 ppm exhibited "marked responses" to SO2 that fall into a "range of likely clinical concern" during moderate exercise, whereas exposures ranging from 0.6 to 1.0 ppm caused 25 to 55% of participants in the exposure studies to demonstrate such responses. *Supplement to the Second Addendum (1986) to Air Quality Criteria for Particulate Matter and Sulfur Oxides (1982): Assessment of New Findings on Sulfur Dioxide Acute Exposure Health Effects in Asthmatic Individuals (USEPA, Office of Research and Development, August 1994), pp.31-32 ["SO2 CD"].* "Substantially greater percentages of moderate and mild asthmatics experienced moderate to severe respiratory symptoms at 0.6 or 1.0 ppm SO2 exposures." *Id., 34.* Symptoms characterized as "severe" include requesting medication after exposure, being unable to perform tasks assigned during the exposure, and/or demanding to terminate the exposure. Id., 34. Based on these studies, EPA revised the SO2 CD with findings that: considerably larger lung function changes and respiratory symptoms of notably greater severity would be projected to occur due to exposure of such individuals to SO2 concentrations of 0.6 to 1.0 ppm while physically active. That is, substantial percentages (> or = 20 to 25%) of mild or moderate asthmatic individuals exposed to 0.6 to 1.0 ppm SO2 during

moderate exercise would be projected to have respiratory function changes and severity of respiratory symptoms that distinctly exceed those experienced as typical daily activities, use of bronchodilator medication, and/or possible seeking of medical attention. *Id., 49.*"

More from this letter is included as an attachment.

The final request in Mr. Yuhnke's letter is our request to the TCEQ, that in order to ensure that the plumes from the CCND facility will not cause short-term SO2 concentrations that may endanger public health, plume modeling should be performed to determine if projected 5-minute peak SO2 concentrations will remain below 0.60 ppm.

16. The draft permit must state what specific technologies will be used for the boiler and control equipment and what the manufacturer guarantees are for emissions from this equipment. Petroleum coke is a toxic oil refining byproduct that needs to adequately controlled at the E.S. Joslin power station.

Learning from the ongoing problems with the Holsom permit, the TCEQ must require that CCND produce specifics on the boiler and control technologies that would be used for this plant along with sufficient manufacturer data that will assure that the equipment can meet the emission limits set out in the permit.

Petroleum coke is a toxic oil refining byproduct that needs to adequately controlled at the E.S. Joslin power station.

The application and TCEQ information project 95% control efficiency without providing sufficient details on the manufacturer or testing to confirm 95% will be achieved.

Petroleum coke is a black solid, particulate matter or fine dust obtained in petroleum refining. The raw product (green coke) contains as much as 15% volatile material, mainly hydrocarbons. These volatile hydrocarbons found in the raw product, green coke are released into the air as a gas and also are transported within the coke dust particles. PAHs are present in petroleum coke. Probably dozen of these benzene-ringed compounds are present in petroleum coke. The presence of these gases, known as Polynuclear or Polycyclic Aromatic Hydrocarbons (PAH's), in the petroleum coke implies that measures should be taken to avoid contact with the product.

Petroleum coke contains both hazardous and toxic compounds which are polycyclic aromatic hydrocarbons. Polycyclic Aromatic hydrocarbons are present in petroleum coke and many PAH, are known cancer-causing agents. The microscopic size of petroleum coke dust particles simply means that exposure to the dust will result in inhalation directly into the sensitive lung tissues. Therefore the only guarantee safe level of petroleum coke exposure is zero dust.

Petroleum coke contains toxic particulate emissions of a fine nature as small as the PM2.5 microns-sized and PM10 particles regulated by the EPA. Exposure to elevated levels of PM2.5 and PM10 particulate (similar to petroleum coke) are being associated in numerous studies with increased premature mortality and serious lung disease. Petroleum coke contains toxic metals which may include vanadium, nickel and selenium. Nickel is a class A carcinogen meaning it causes cancer in humans and also causes birth defects, reproductive effects, and mutations. Selenium is a neurotoxin and causes birth defects.

Exposure to petroleum coke dust has been associated with respiratory impairment and with irritation of the eyes and skin. Research indicates that children exposed to even small concentrations of dust particles experience aggravation of bronchitis and decreases in lung function. Continual exposure to low-level of PAH gasses could cause long-term health problems. Exposure occurs through ingestion, direct contact with waste materials, inhalation of contaminated air, and absorption through skin. Exposure to these gases may cause cancer, genetic damage, and damage, suppress the immune system, central nervous system damage, and damage to various vital organs such as the liver and kidneys. PAH gases can be passed from the mother to the developing fetus if the mother is exposed to them while pregnant. They also collect in breast milk and are passed on to the child in that way.

17. ESLs have not been appropriately defined by the TCEQ.

The Effects Screening Levels used in the Calhoun County Navigation District's permit review are not set at levels known to protect public health. The TCEQ lacks scientific information and a peer review process, among numerous other concerns, to confirm the validity of ESLs in protecting public health.,,

Inadequacy of the TCEQ ESLs is an overall concern with the agency's permit health effects review process, particularly since the ESLs have never been subjected to external peer-review by expert toxicologists.

Three toxicologists (Marc A. McConnell, Lance M. Hallberg, and Marvin S. Legator) and two chemical engineers (Robert Notzon, B.E. and Jim Tarr, P.E.) have independently evaluated the TCEQ's ESL guidelines and identified a set of flaws which they published in three separate papers. The late Dr. Marvin Legator served for many years as a genetic toxicologist and Director of the Department of Environmental Toxicology at the University of Texas Medical Branch at Galveston, Texas and director of UTMB's Toxic Assistance Program.

These five experts concluded that the TCEQ's Effects Screening Level (ESL) process had no scientific basis and was not designed or used to protect public health. Such a poorly designed regulatory system may be subverted for discretionary purposes. Uncertainties in the ESLs makes their application during permit reviews risky science that the public is usually not informed about by the TCEQ.

Summary of these flaws and lack of good toxicological-air pollution science in Texas is further reported by Robert Stephen Notzon, B.E., in partial fulfillment of his Doctor of Jurisprudence degree from the University of Texas at Austin law school and also for a master's thesis submitted to LBJ School of Public Affairs at the University of
Texas at Austin in December 1996 titled--Texas' Effects Screening Levels: The Secret to Air Quality Regulation or The Secret Behind Air Quality Regulation.

Ten major flaws are identified in the Texas ESL process and they are listed here as follows. Each flaw represents a concern with the Point Comfort-Sandy Creek permit.

The ESLs are often set at artificial levels too high to be truly protective of the health of the public, including children, even though the Texas Clean Air Act requires that TCEQ protect the general public from unacceptable concentrations of toxic air emissions. In fact Dr. Michael Honeycutt, director of TCEQ's Toxicology program, has publicly stated at recent public meetings in Houston that the current ESLs need to be revised such as 1,3-butadiene and others. While the TCEQ's toxicology staff is reviewing the ESLs, the Sandy Creek coal-fired power plant draft permit continues through the approval process even though theTCEQ's staff know that some, if not all, of the ESLs used in the review process are artificially set too high.

ESLs are not state ambient air quality standards set to protect public health. They are merely internally developed "guidelines" and not ambient air standards. Even Louisiana has a set of air toxics standards, some which are more protective than Texas's ESLs.

There are no Texas regulations governing the ESL process. TCEQ uses an internally developed purely informal discretionary process when it reviews a permit to check if the ESLs are exceeded, but this effort fails to protect public health for several reasons. The TCEQ engineers may not formally request that all toxic pollutants be reviewed for health effects. For example, radon and its carcinogenic byproducts were not reviewed for the CCND draft permit. If the TCEQ engineers do not ask the staff toxicologists to review a specific toxic air pollutant such as radon and its byroducts, the staff toxicologists will then ignore reviewing any other toxic air pollutants even if the proposed source is emitting such toxic substances.

ESLs have not been subjected to true scientific peer review external to the TCEQ: The ESLs lack a legitimate scientific peer review process in their development and application. No public review process has occurred either as to the artificial and contrived nature of the ESLs and the agency's inappropriate permit review process.

Questionable, if not faulty, bases were used for at least a third of the ESLs as determined in a recent review of the ESLs in a Master's thesis by Robert Notzon and a peer-reviewed journal article published by Dr. Marvin Legator et al.

Questionable, if not faulty, process has been used to derive the ESLs as determined in a recent review of the ESLs in a Master's thesis by Robert Notzon and a peer-reviewed journal article published by Dr. Marvin Legator et al.

There is no method for validating either the process or the final ESL values as determined in a recent review of the ESLs in a Master's thesis by Robert Notzon and a peer-reviewed journal article published by Dr. Marvin Legator et al.

There is no complete agency documentation of the ESL derivation process as determined in a recent review of the ESLs in a Master's thesis by Robert Notzon and a peer-reviewed journal article published by Dr. Marvin Legator et al.

The guideline approach reduces accountability of the ESL process according to a Master's thesis by Robert Notzon and a peer-reviewed journal article published by Dr. Marvin Legator et al.

The toxicology review does not consider synergistic impacts. The individual ESLs and the ESL review process itself typically does not take into account synergistic and/or additive effects of exposures to different toxins occurring together in a toxic soup or complex mixture of substances such as particulate matter produced by combustion processes like a coal-fired power plant releases.

18. The TCEQ should be regulating radon exposure to radon and its carcinogenic byproducts.

Radon is known as TENORM, technologically enhanced naturally occurring radioactive materials. Radon is a radionuclide classified as hazardous air pollutant/HAP under Title III of the Clean Air Act.

Radon and its radioactive relatives include Pollonium 210 and Lead 210, both called Radon daughters/progeny and both are carcinogens.

TCEQ's Regulatory Definition of "Air Contaminant" in state law includes "radioactive material" and radon should therefore be considered as "radioactive material."

As used in the TCAA in §382.003(2), "Air Contaminant" is rather broadly defined and means the following which are all, by varying degrees, different forms of air pollution by being pollutants such as those emitted coal-fired power plants.

"Air Contaminant" is defined as: "particulate matter, radioactive material, dust, fumes, gas, mist, smoke, vapor, or odor, or any combination thereof produced by processes other than natural."

Radon gas emissions at the proposed CCND coal-fired power plant results from its presence in the coal, and significant quantities of radon gas are released into the air during large-scale coal combustion. However, neither the permit application, the TCEQ's technical review, nor draft permit present information on the average concentrations of radon and its radioactive relatives in the coal to be used at the Sandy Creek plant.

While Radon is gone in a few days, it turns into two carcinogenic byproducts, Pollonium 210 and Lead 210. Air pollution health effects of Pollonium 210 and Lead 210 have not been addressed in the draft permit.

Concerns exist about air pollution of Radon and its two carcinogenic byproducts, Pollonium 210 and Lead 210.

The highest concentrations would be in the Point Comfort area closest to the Calhoun County Navigation District Point Comfort plant.

Conclusion and Recommendations

In conclusion, we suggest the following changes to the permit:

Particulate emissions should be lowered to no greater than 0.022 lb/mmbtu as is being proposed for the CPS plant.

CCND should be required to use wet flue gas desulfurization to reduce sulfur pollution.

An analysis should be required to determine whether IGCC technology is Best Available Control Technology (BACT), and what levels of pollution reduction could be achieved using it.

All sulfur and NOx emissions should be offset by emissions reductions at other facilities as is being required in the draft permit for San Antonio

Global warming gases should be mitigated as is being required in other states.

Federal guidance requires a case-by-case analysis for mercury, which is not included in the draft permit, and should be added.

The permit should clearly specify carbon absorption for mercury removal to a level of no greater than 2 x 10-6 lb/MWh as has been proposed by the applicant.

It should be specified in the permit that CCND may not purchase mercury credits to meet their emission limit.

Increased controls of fugitive emissions should be required.

The TCEQ must implement ambient air monitoring in Point Comfort and Victoria.

The TCEQ must provide a full toxicological study including adequate rationale for the determination that a potential exceedence of the ESL for silica is considered acceptable.

Diesel emissions and dust emissions from the train and coal transport should be included with the other air impacts in the permit.

CCND should be required to provide manufacturer data assuring that they will be able to meet the emission limits in the permit.

The permit should address radon and its carcinogenic by products as air contaminants.

Respectfully submitted:

Tom "Smitty" Smith, Director
Public Citizen - Texas
1002 West Avenue Suite 300
Austin, TX 78701
(512) 477-1155

Karen Hadden, Director
Sustainable Energy & Economic Development Coalition
611 S. Congress, Suite 200
Austin, TX 78704
(512) 479-7744

Becky Bornhorst, Board representative
Blue Skies Alliance
400 N. Main St.
Duncanville, TX 75116
(972) 296-9100

Dr. Neil Carman

Texas State Sierra Club and Local Regional Groups
1202 San Antonio St.
Austin, TX 78701
(512) 477-1729

Ed Parton
Texas Black Bass Unlimited
1102 Lisa Lane
Kingwood, TX 77339
(281) 723-3828

Attachments:
Comparison of proposed emissions from CPS plant and proposed emissions from the CCND plant
Texas Medical Association Report of Committee on Maternal and Perinatal Health
Additional Excerpt from Robert Yuhnke's May 21, 1999 letter to Roger C. Westman, Air Quality Program Manager of the Allegheny County Health Department

CATF, "Dirty Air Dirty Power," 2004. Metro area statistics can be found at cta.policy.net/dirtypower/
Ibid.
Dockery, Douglas W, and Pope, C Arden III, Acute Respiratory Effects of Particulate Air Pollution, Annual Review Public Health, 1994, 15:107-32.
ATS. Health effects of outdoor air pollution. Committee of the Environmental and Occupational Health Assembly of the American Thoracic Society. American Journal of Respiratory & Critical Care Medicine 1996, 153:3-50.

C. Arden Pope, Richard Burnett, Michael Thun, Eugenia Calle, Daniel Krewski, Kazuhiko Ito, and George Thurston, "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution," Journal of the American Medical Association Vol 287, No. 9, March 6, 2002, 1132-1141.
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Annette Peters, PhD; Douglas W. Dockery, ScD; James E. Muller,MD; Murray A. Mittleman, MD, Dr PH, Increased Particulate Air Pollution and the Triggering of Myocardial Infarction, Circulation, June 12, 2001.
Prospects for Attaining the State Ambient Air Quality Standards for Suspended Particulate Matter (PM10), Visibility Reducing Particles, Sulfates, Lead, and Hydrogen Sulfide: A Report to the Legislature, California Air Resources Board, Sacramento, CA, April 11, 1991 Bar Code: 5136 Call No: TD 883.1 P767 1991-2.
Excerpted from pp. 25-27 of Chapter IV - Suspended Particulate Matter (PM10) Section B. Ambient Air Quality Standards and the Health Effects of PM10 B.2.

Standards for PM10.
Communication with Dr. Ramon Alvarez, Environmental Defense, December 13, 2004.
Big Bend Regional Aerosol and Visibility Observational Study.
State of Texas Mileage Guide
TCEQ CAMx v 1.13 PiG tracers on DFW core domain June 19th 1995 at 14:00 hrs.
25 TexReg 4102, May 5, 2000
Propose Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Interstate Air Quality Rule) pg 14, 53, 77-78
http://www.epa.gov/ttncaaa1/t1/fr_notices/iaq_ritfpmo_pr.pdf

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"Bracing for Climate Change in the Constitution State," Environmental Defense report, 2004.
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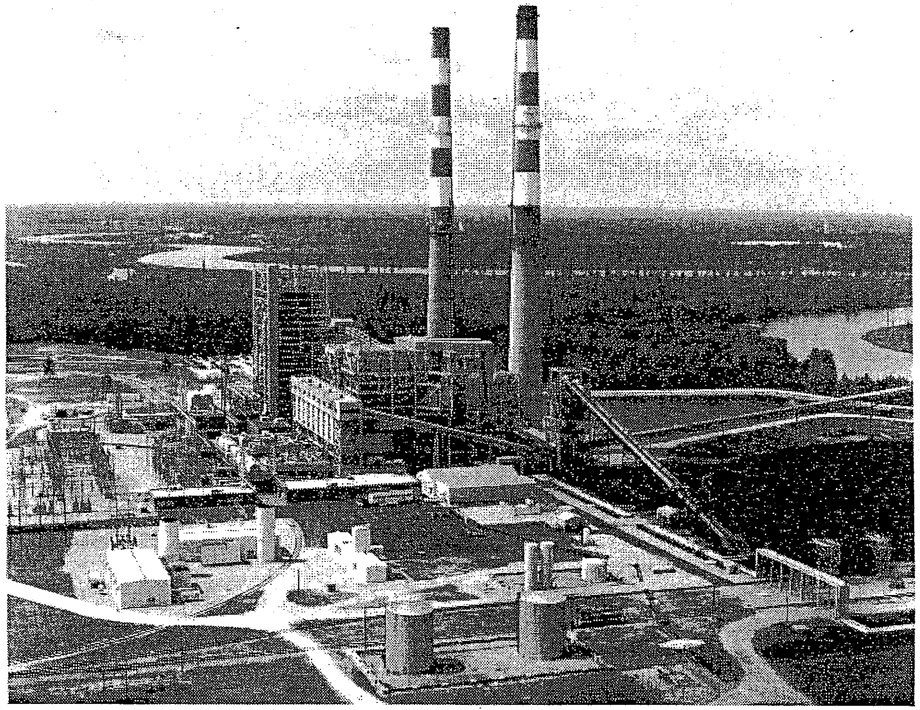
Tracking New Coal-Fired Power Plants



Coal's Resurgence in Electric Power Generation

NETL

July 25, 2005

Tracking New Coal-Fired Power Plants

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

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

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

Sources: 1 - Energy Central Daily & Wall Street Journal

NETL

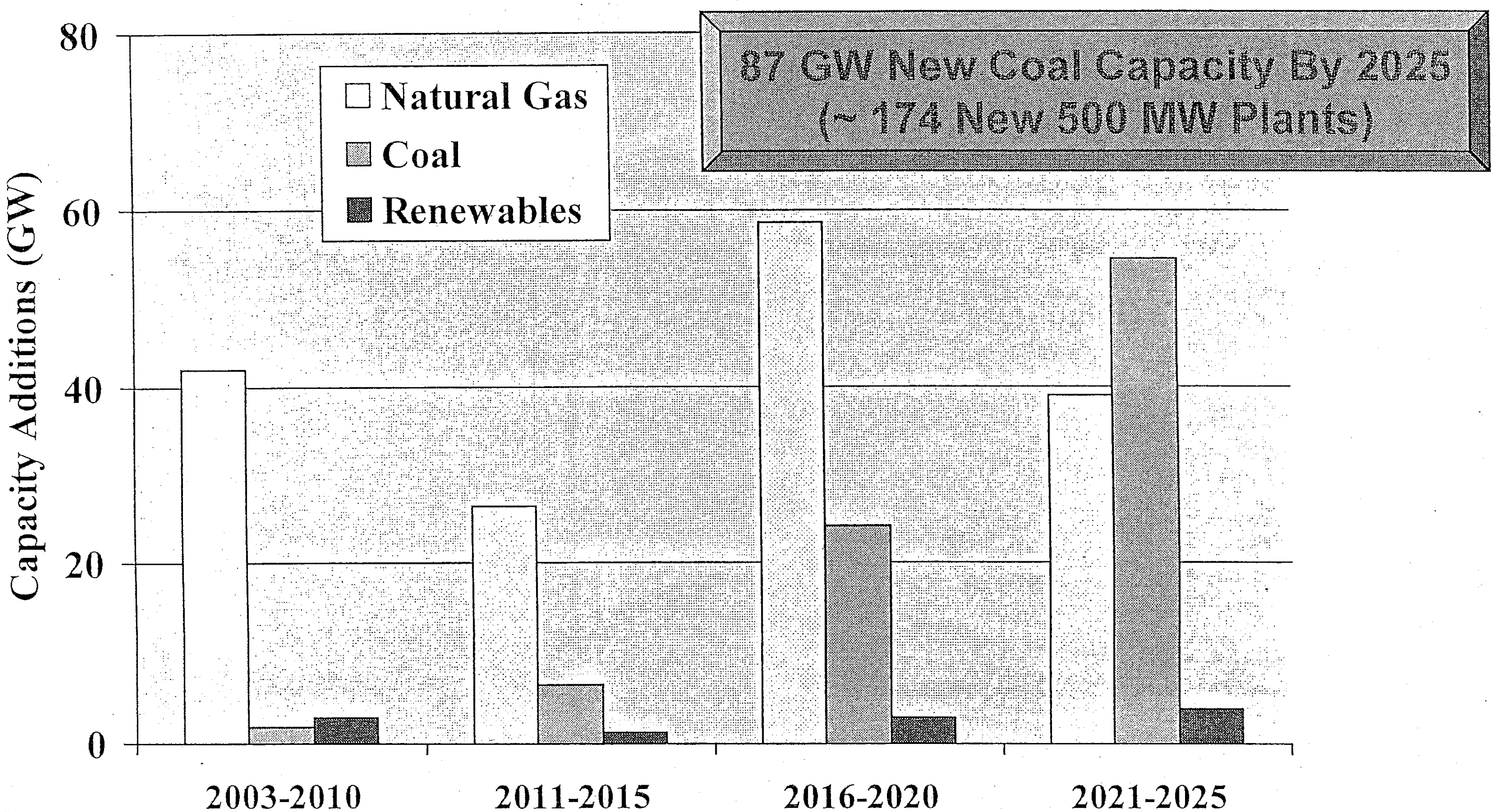
NETL Contacts: Scott Klara, klara@netl.doe.gov
Erik Shuster, erik.shuster@sa.netl.doe.gov

87 GW New Coal Capacity By 2025

(Accounts for 33% of New Capacity Additions)

New Electricity Capacity Additions

(EIA Reference Case)

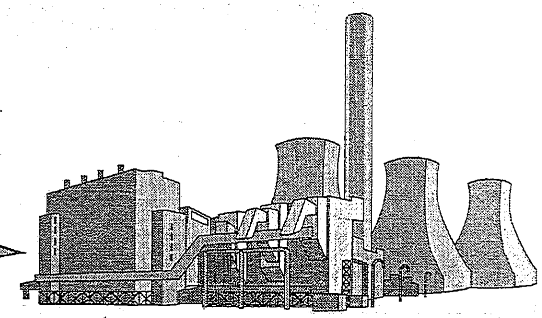


Source: Data Derived From EIA Annual Energy Outlook 2005

NETL Contacts: Scott Klara, klara@netl.doe.gov
Erik Shuster, erik.shuster@sa.netl.doe.gov

Coal's Resurgence in Electric Power Generation

124 Proposed Plants
73 GW Power
$ 99 Billion Investment



Equivalent Power
for
73 Million Homes

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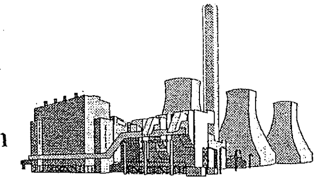
NETL Contacts: Scott Klara, klara@netl.doe.gov
Erik Shuster, erik.shuster@sa.netl.doe.gov

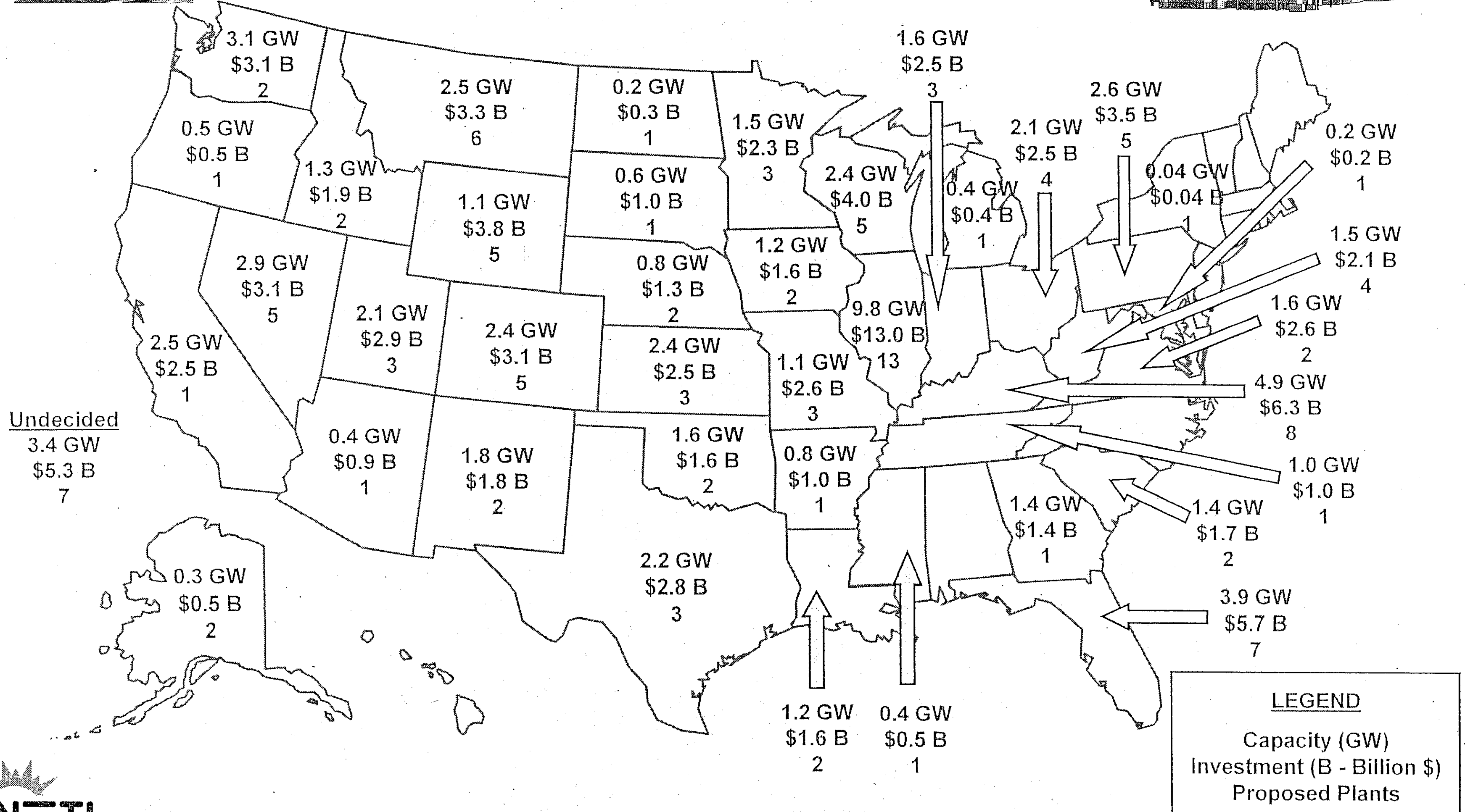
Coal's Resurgence in Electric Power Generation

Proposed New Plants

Equivalent Power
for
73 Million Homes

124 Plants
73GW
$ 99 Billion



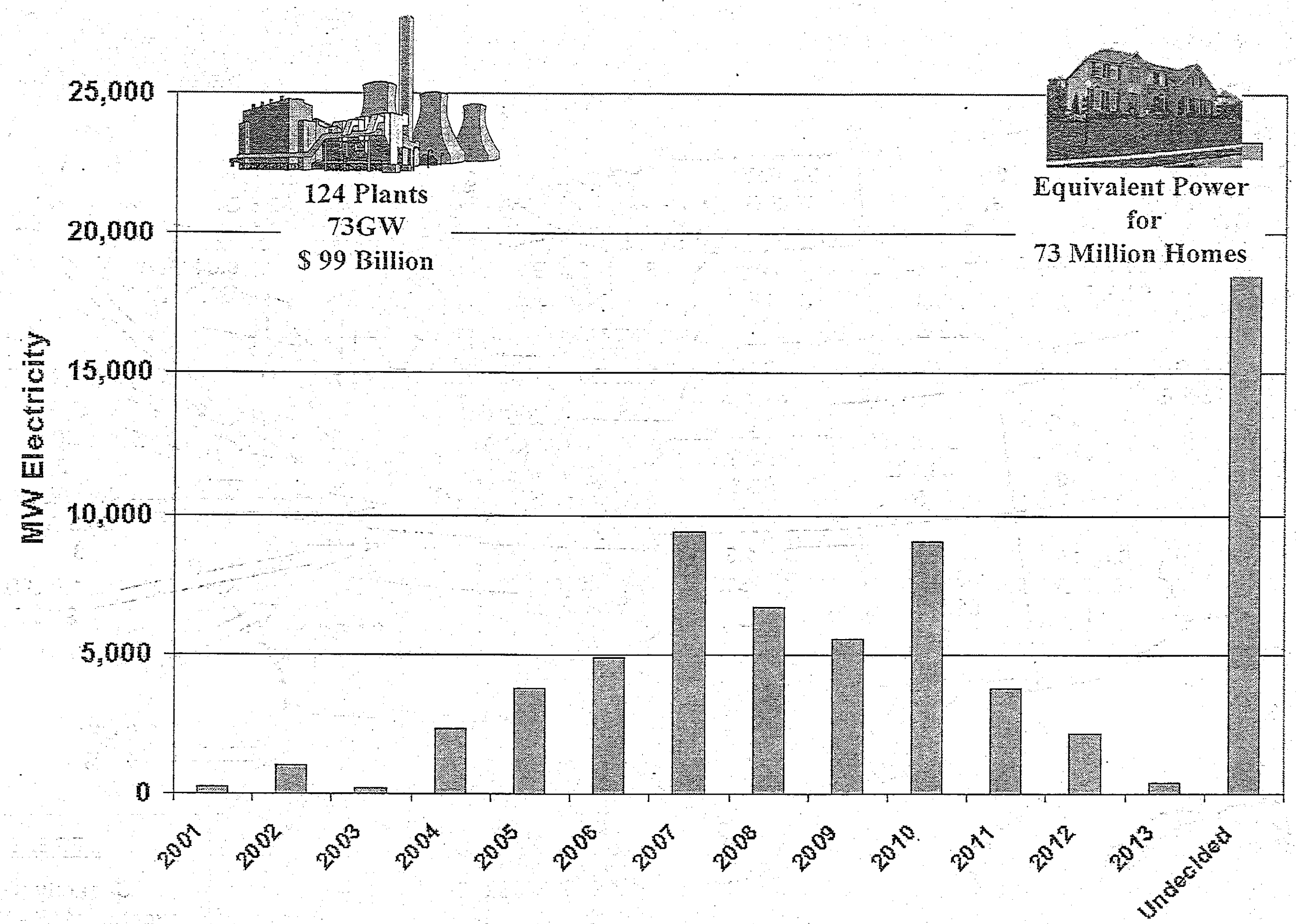


NETL

NETL Contacts: Scott Klara, klara@netl.doe.gov
Erik Shuster, erik.shuster@sa.netl.doe.gov

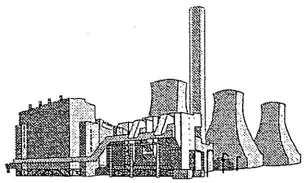
OCES 7/25/2005

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



NETL Contacts: Scott Klara, klara@netl.doe.gov
Erik Shuster, erik.shuster@sa.netl.doe.gov

Coal's Resurgence State Summary



124 Plants
73 GW
$ 99 Billion

Equivalent Power
for
73 Million Homes

State	Plants	Capacity (MW)	% Capacity	Investment (Million $)	% Investment
Alabama	0	0	0.0	$0	0.0
Alaska	2	300	0.4	$521	0.5
Arizona	1	400	0.5	$939	0.9
Arkansas	1	800	1.1	$1,000	1.0
California	1	2,500	3.4	$2,500	2.5
Colorado	5	2,389	3.3	$3,142	3.2
Florida	7	3,935	5.4	$5,650	5.7
Georgia	1	1,400	1.9	$1,400	1.4
Idaho	2	1,250	1.7	$1,850	1.9
Illinois	13	9,763	13.4	$13,025	13.1
Indiana	3	1,600	2.2	$2,500	2.5
Iowa	2	1,190	1.6	$1,600	1.6
Kansas	3	2,360	3.2	$2,510	2.5
Kentucky	8	4,946	6.8	$6,357	6.4
Louisiana	2	1,200	1.6	$1,600	1.6
Maryland	1	180	0.2	$180	0.2
Michigan	1	425	0.6	$425	0.4
Minnesota	3	1,456	2.0	$2,300	2.3
Mississippi	1	440	0.6	$500	0.5
Missouri	3	1,125	1.5	$2,550	2.6
Montana	6	2,513	3.4	$3,315	3.3
Nevada	5	2,915	4.0	$3,615	3.6
Nebraska	2	820	1.1	$1,295	1.3
New Mexico	2	1,800	2.5	$1,800	1.8
New York	1	40	0.1	$40	0.0
North Dakota	1	175	0.2	$300	0.3
Ohio	4	2,090	2.9	$2,455	2.5
Oklahoma	2	1,600	2.2	$1,600	1.6
Oregon	1	500	0.7	$500	0.5
Pennsylvania	5	2,570	3.5	$3,525	3.6
South Carolina	2	1,440	2.0	$1,720	1.7
South Dakota	1	600	0.8	$1,000	1.0
Tennessee	1	1,000	1.4	$1,000	1.0
Texas	3	2,150	2.9	$2,800	2.8
Utah	3	2,070	2.8	$2,850	2.9
Virginia	2	1,600	2.2	$2,600	2.6
Washington	2	3,100	4.2	$3,100	3.1
West Virginia	4	1,495	2.0	$2,055	2.1
Wisconsin	5	2,400	3.3	$4,000	4.0
Wyoming	5	1,090	1.5	$3,835	3.9
Undecided	7	3,350	4.6	$5,300	5.3
TOTALS	124	72,977	100	$99,254	100

NETL Contacts: Scott Klara, klara@netl.doe.gov
Erik Shuster, erik.shuster@sa.netl.doe.gov

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

SPONSOR	PROPOSED LOCATION	SIZE TECHNOLOGY	TIMING Status - (Date indicates latest reference) In Service - Planned Date	INVESTMENT	COAL SOURCE	SOURCES
~~TVA Bellefonte Site~~	~~Alabama~~ ~~Jackson County~~	~~1500 MW~~ ~~IGCC Texaco~~	Cancelled (4/2003) ~~In Service - 2005~~	~~~ $ 1.5 Billion~~	~~High Sulfur Coal~~ ~~Illinois Basin~~	8, 7, 9, 12
Nuvista	Alaska Bethel	100 MW	Proposed (3/2004) In Service - 2010	~ $ 100 Million	Coal	11
Usibelli Coal Mine Inc.	Alaska Healy	200 MW	Proposed (5/2003) In Service - TBD	$ 421 Million	Coal	1
~~Reliant Resources~~ ~~Hopi Tribe~~	~~Arizona~~ ~~Not yet located~~	~~1,200 MW~~	Cancelled (5/2002) ~~In Service - 2008~~	~~~ $ 1.2 Billion~~	~~low Sulfur Sub-bituminous~~	11, 24
Tuscon Electric Power	Arizona Springerville	400 MW	Approved (11/2003) In Service - 2006	$ 939 Million	Sub-Bituminous	2, 3, 4, 12
~~Alabama Electric~~	~~Arizona~~ ~~Sumter County~~	~~500 MW~~	Cancelled ~~In Service - 2007~~	~~~ $ 500 Million~~	~~Sub-Bituminous~~	9, 6
~~Fort Chaffee Authority~~	~~Arkansas~~ ~~Fort Chaffee~~	~~2 Plants~~ ~~750 MW each~~	Cancelled ~~In Service - 2007~~	~~$ 2.5 Billion~~	~~Arkansas Coal~~	11
LS Power Development	Arkansas Osceola	800 MW	Permitting (10/2003) In Service - 2008	$ 1 Billion	Powder River Basin Coal	6, 9, 11
Fernald Power	California Humbolt City	2,500 MW	Proposed (10/2001) In Service - TBD	~ $ 2.5 Billion	Coal	11
Radar Acquisitions Corp. / Kiewit	Colorado	400 - 500 MW	Feasibility Study (10/2003) In Service - TBD	~$ 500 Million	Coal	11
DOE Foster Wheeler	Colorado Colorado Springs	150 MW CFB	On Hold (12/2003) In Service - 2008	$ 275 Million	Coal	1, 11
Tri-State Generation and Transmission	Colorado Front Range	1,000 MW	Proposed (10/2004) In Service - 2011	~$ 1 Billion	Coal	1

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NETL

NETL Contacts: Scott Klara, klara@netl.doe.gov
Erik Shuster, erik.shuster@sa.netl.doe.gov

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Larmar Light & Power Ark. River Power Auth.	Colorado Lamar	39 MW increase Conversion	Feasibility study (8/2004) In Service - TBD	$ 67 Million	Coal to replace natural gas	2
~~Tri State Generation and Transmission~~	~~Colorado~~ ~~Las Animas~~	~~3 Units~~ ~~400 MW each~~	Cancelled (4/03) ~~In Service 2005,06,07~~	~~$ 1.2 Billion~~	~~Coal~~	11, 4, 12
Xcel Energy	Colorado Pueblo	750MW	Air Permit (7/2005) In Service - 2009	$ 1.3 Billion	Coal	1, 11
~~Deseret Generation & Transmission Corp.~~	~~Colorado~~ ~~Rangely~~	~~80 MW~~	Cancelled (1/2005) ~~In Service 2004~~	~~$ 140 Million~~	~~Waste Coal~~	1, 3, 12
Florida Municipal Power Agency	Florida	500-600 MW	Considering (10/2002) In Service - 2009	$ 600 Million	Coal	11
Florida Power & Light	Florida Crystal River	100 MW	Operational In Service - 2001	~ $ 100 Million	Coal	12
Jacksonville Electric	Florida Duval	(2) 300 MW Units CFB	Operational (7/2002) In Service - 2002	~$ 600 Million	Coal/Pet Coke	12, 3, 9
Orlando Utilities Comm. U.S. DOE	Florida Orange County	285 MW IGCC	Proposed (10/2004) In Service - 2010	$750 Million	Coal	1, 2
~~Lakeland Electric & Water~~	~~Florida~~ ~~Polk County~~	~~350 MW~~	Cancelled ~~In Service TBD~~	~~~$ 350 Million~~	~~Coal~~	12
Seminole Electric Cooperative	Florida Putnam County	750 MW	Proposed (3/2005) In Service - 2012	$1.2 Billion	Coal	1, 11
Florida Power & Light	Florida St. Lucie County	(2) 425 MW Units	Considering (3/2005) In Service - 2012, 13	~$1 Billion	Coal	1, 11
JEA	Florida Taylor County	800 MW	Considering (7/2005) In Service - 2012	$1.4 Billion	Coal	1, 2

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LS Power Development	Georgia Early County	1,200 - 1,600 MW	Permitting (8/2002) In Service - 2005	~ $1.4 Billion	Coal	6
Sempra Energy Resources	Idaho Elmore or Jerome	750 MW	Proposed (9/2004) In Service - TBD	$1 Billion	Coal Low-Sulfur	21
Southeast Idaho Energy LLC	Idaho Pocatello	~ 500 MW IGCC	Proposed (3/2005) In Service - 2010	$850 Million	Coal	2
Dynegy	Illinois Baldwin	2 Plants 650 MW each	Proposed (10/2001) In Service - 2007	$ 1.5 Billion	Illinois Coal	1
Illinois Energy Group	Illinois Benton	2 units 750 MW each	Proposed (8/2002) In Service - TBD	$ 1.7 Billion	Coal	11, 17
Corn Belt Energy (DOE)	Illinois Elkhart	91 MW LEBS	Development (6/2005) In Service - 2004	$ 140 Million	Waste Coal	1, 2, 8, 12
Turris Coal Company	Illinois Elkhart	25 - 35 MW	Proposed (10/2001) In Service - TBD	~ $ 35 Million	Coal	11
Indeck Energy Service	Illinois Elwood	600 MW CFB	Final Permitting (6/2005) In Service - 2007	$1 Billion	Illinois Coal	1, 12
Clean Coal Power Resources	Illinois Fayette County	2,400 MW Gasification	Proposal (10/2002) In Service - TBD	~ $2.8 Billion	Coal	11
EnviroPower	Illinois Franklin County	500 MW	Permitting (5/2003) In Service - 2007	~ $ 500 Million	Coal	8, 12
Madison Power Corp.	Illinois Marion	500 MW Gasification	Proposal (10/2004) In Service - TBD	$ 2.0 Billion	Coal (Mine-Mouth)	2
Southern Illinois Power	Illinois Marion	120 MW	Operational (6/2003) In Service - 2003	$ 50 Million	Bituminous Coal Fines	8, 9, 12

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Erora Group	Illinois Taylorville	677 MW IGCC / Coprod.	Proposal (3/2005) In Service - TBD	~ $700 Million	Coal (Mine-Mouth)	1, 19
Peabody Prairie Energy Campus	Illinois Washington City	2 units 750 MW each	Air Permit Rejected (6/2005) In Service - 2008	$ 2.0 Billion	Illinois Coal High Sulfur	1, 11, 12
Steelhead Energy Company LLC	Illinois Williamson County	545 MW IGCC	Proposal (6/2005) In Service - TBD	~600 Million	Coal	1
Cinergy Corp.	Indiana Edwardsport	600 MW IGCC	Proposal (10/2004) In Service - TBD	$ 900 Million	Coal	23
~~EnviroPower~~	~~Indiana Fayette County~~	~~525 MW~~	~~Development (7/2002) In Service 2004~~	~~~ $ 525 Million~~	~~Waste Coal~~	12, 8
~~EnviroPower~~	~~Indiana Pike County~~	~~500 MW~~	~~Initiate 2001~~ Cancelled 2002	~~$ 600 Million~~	~~Waste Coal~~	2, 5, 8, 9, 12
Tondu Corp,	Indiana St. Joseph County	630MW IGCC	Considering (3/2005) In Service - TBD	$ 1 Billion	Coal	2
EnviroPower	Indiana Sullivan County	500 MW	Permitting - (10/2002) In Service - TBD	$ 600 Million	Waste Coal	2, 5, 8, 9, 12
~~Alliant Energy~~	~~Iowa~~	~~450 MW~~	~~Development (5/2003)~~ Cancelled - 2003	~~~ $ 450 Million~~	~~Coal~~	12, 1
MidAmerican Energy	Iowa Council Bluffs	790 MW Super-critical	Construction (8/2004) In Service - 2007	$ 1.2 Billion	Coal	13, 1, 8, 11
Dairyland Power Cooperative	Iowa Mitchell or Chickasaw	400 MW	On Hold (12/2004) In Service - 2009-2014	~$400 Million	Low Sulfur PRB and Colorado	2, 11
Sunflower Electric & International Energy	Kansas Garden City (Holcomb)	660 MW	Near Construct. (6/2005) In Service - 2008	~$660 Million	Coal PBR	1, 11, 12

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Kansas City Power & Light	Kansas Iatan	850 MW	Development (2/2005) In Service - TBD	~ $ 1 Billion	Coal	8, 1
Great Plains Energy	Kansas	850 MW	On Hold (7/2004) In Service - TBD	~ $ 850 Million	Coal	1,
EnviroPower	Kentucky Calvert City	500 MW	Development (8/2002) In Service - TBD	$ 600 Million	Coal & Waste Coal	1, 2
Peabody Group "Thoroughbred"	Kentucky Muhlenberg	2 Units 750 MW each	Approved (3/2005) In Service - 2007	$ 2.1 Billion	Western Kentucky High Sulfur Coal	1, 3, 9, 12, 16
Estill County Energy Partners	Kentucky Estill County	110 CFB	Development (10/2004) In Service - 2008	$ 150 Million	Waste Coal	11, 2, 18
Cash Creek Generation	Kentucky Henderson City	1,000 MW	Permitting (11/2001) In Service - 2006	$ 1 Billion	Coal	1
~~Kentucky Mountain Power (EnviroPower)~~	~~Kentucky Knott County~~	~~525 MW~~	Suspended (4/2004) In Service - 2006	~~$ 600 Million~~	~~Waste Coal & New Coal~~	1, 2, 9, 12, 18
East Kentucky Power co-op	Kentucky Maysville	268 MW CFB	Operational (3/2005) In Service - 2005	$ 367 Million	Coal	15, 8, 12
East Kentucky Power co-op	Kentucky Maysville	278 MW CFB	Proposed (11/2004) In Service - 2009	$ 400 Million	Coal	2, 22
Global - Kentucky Pioneer Energy - DOE	Kentucky Clark County	540 MW IGCC	Delayed (6/2004) In Service - 2004	~ $ 540 Million	20% Coal 80% Waste	12, 1, 11, 18
LG&E Powergen	Kentucky Trimble County	750 MW Super-critical	Proposal (11/2004) In Service - 2010	$1.2 Billion	Coal Illinois Basin	11, 1, 2
Cleco Power	Louisiana Boyce	600 MW 2-CFB units	Proposed (7/2005) In Service - TBD	$1.0 Billion	Coal	1

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~~NRG Energy~~	~~Louisiana New Roads~~	~~675 MW~~	Cancelled - 2002	~~~ $ 675 Million~~	~~Coal~~	12
NRG Energy	Louisiana Pointe Coupee	600 MW	Initiate - 2001 In Service - 2006	~ $ 600 Million	Coal	2
AES Corporation	Maryland Cumberland	180 MW CFB	Operational In Service - 2001	~ $ 180 Million	Maryland Coal	2, 7
Manistee Saltwork Tondu Corp.	Michigan Manistee	425 MW	On Hold (11/2004) In Service - 2006	~ $ 425 Million	Coal	2, 12
Great River Energy	Minnesota Dakota County	250-500 MW IGCC or CFBC	Proposed (2/2002) In Service - 2008	~ $500 Million	Coal	11
~~Minnesota Power~~	~~Minnesota Grand Rapids~~	~~225 MW~~	Cancelled (8/2002) ~~In Service 2005~~	~~~$200 Million~~	~~Coal~~	8, 11
Excelsior Energy Mesaba Energy Project	Minnesota Hoyt Lakes	531 MW Gasification	Permitting (6/2005) In Service - 2010	$1.2 Billion	Coal	11, 19
Xcel Energy / LS Power	Minnesota Rosemount	550 MW	Preliminary (3/2003) In Service - TBD	~$ 600 Million	Coal	1, 2
Tractebel Power	Mississippi Choctaw County	440 MW	Operational In Service - 2002	$ 500 Million	Lignite	2, 11,12, 7
Accociated Electric Cooperative Inc.	Missouri Carroll County	TBD	Proposed (4/2005) In Service - TBD	$1 Billion	Coal	2
Springfield City Council	Missouri Springfield	275 MW Additional	Voters Reject (10/2004) In Service - 2007	~ $ 250 Million	PRB Coal	11
~~Great Plains Power~~	~~Missouri Weston~~	~~750 MW~~	Not being Considered (5/2004) In Service - 2005	~~~$750 Million~~	~~Coal~~	12, 1, 8

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Great Plains Energy Kansas City Power & Light	Missouri Platte County	850 MW	Proposed (4/2005) In Service - 2010	$ 1.3 Billion	Coal	1, 12
~~Composite Power~~	~~Montana~~ ~~Bear Creek~~	~~4 Plants~~ ~~500 MW each~~	Cancelled (2/2003) ~~In Service - 2004,6,8~~	~~$ 1.5 Billion~~	~~Montana~~ ~~Coal~~	2, 8, 12
Bull Mountain Development	Montana Billings	2 Units 350 MW each	Air Permit Expired (7/2005) In Service - TBD	~ $ 700 Million	Coal	8, 12, 11
Southern Montana Electric Gen & Trans	Montana Great Falls	250 MW	Proposed (3/2005) In Service - 2010	$ 515 Million	Coal	21, 11
Centennial Power	Montana Hardin	113 MW	Construction (8/2004) In Service - 2005	~ $ 150 Million	Coal	11, 1, 8, 12
Great Northern Power Development / Kiewit	Montana Miles City	500 MW CFB	Proposal (8/2004) In Service - 2008	$ 900 Million	Lignite (Wind also)	1, 2, 11, 12
Comanche Park LLC	Montana Yellowstone City	2 Units 100 MW each	Development (7/2002) In Service - 2004-05	$ 300 Million	Montana Coal	1
Bechtel / Kennecott Energy	Montana Undetermined	750 MW Phase I	Proposal (10/2003) In Service - 2010	~ $ 750 Million	Montana (Mine-Mouth) Coal	11
Nevada Power	Nevada	500 MW	Feasibility Study (11/2003) In Service - 2010	~ $ 500 Million	Coal	11, 2
Sempra Granite Fox Power	Nevada Gerlach	2 - 725MW Units Super-critical	Proposal (7/2005) In Service - 2010, 11	$ 2.0 Billion	Powder River Basin Coal	2, 11
Newmont Mining Corp.	Nevada Elko	200 MW	Considering (7/2004) In Service - 2007	~ $ 200 Million	Coal	1, 12
Barrick Gold	Nevada East of Reno	115 MW	Considering (7/2004) In Service - TBD	~ $ 115 Million	Coal	1

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White Pine Energy	Nevada White Pine County	500 to 800 MW	Considering (2/2004) In Service - 2010	~ $ 0.6 - 1 Billion	Coal	1, 2
Hastings Utilities, Grand Island	Nebraska Hastings	220 MW	Board Approved (12/2004) In Service - 2012	$ 445 Million	Coal	2
Omaha Public Power District	Nebraska Nebraska City	600 MW	Near Construction (4/2005) In Service - 2009	$ 850 Million	Powder River Basin Coal	1, 11
Steag Power / Navajo Nation	New Mexico Farmington	1,500 MW	Proposal (11/2003) In Service - 2007	$1.5 Billion	Coal	1, 2, 12
Peabody Energy	New Mexico Star Lake	300 MW	Permitting stage (10/2004) In Service - 2006	~ $ 300 Million	Coal	11, 12, 8
Jamestown Board of Public Utilities	New York Jamestown	40 MW CFB	Proposal (4/2005) In Service - 2008	~ $ 40 Million	Coal, Petroleum coke, Wood	12
Montana Dakota Utility Westmoreland Power	North Dakota Gascoyne	175 MW	Permitting (6/2005) In Service - 2010	$ 300 Million	North Dakota Lignite	2, 3, 4, 8, 12
~~Great River Energy~~	~~North Dakota TBD~~	~~500 MW~~	Canceled (1/2003) In Service - 2010	~~$ 700 Million~~	~~North Dakota Lignite~~	11, 12, 1
Nordic Energy	Ohio Ashtabula	830 MW Cogeneration	Permitting (5/2004) In Service - 2006	$1.2 Billion	Coal	8, 11
Dominion Energy	Ohio Conneaut	600MW	Considering (7/2004) In Service - 2010	~ $600 Million	Coal	11
Global Energy	Ohio Lima	580 MW IGCC	Permit/Develop (10/2004) In Service - 2007	$ 575 Million	Coal Fines	1, 7, 3, 9, 11, 12
Sunoco	Ohio Scioto County	80 MW Cogeneration	Proposed (9/2004) In Service - 2006	~ $ 80 Million	Coal	12

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SynFuel	Oklahoma Enid	600 MW Gasification	Initiate - 2001 In Service - 2004	~$ 600 Million	Coal	8
LS Power Development	Oklahoma Sequoyah	1,000 MW	On Hold (8/2002) In Service - TBD	~ $ 1 Billion	Coal	6, 8
PacifiCorp	Oregon	500 MW	Initiate In Service - 2004	~ $ 500 Million	Coal	8
~~AES Corporation~~	~~Pennsylvania Beaver~~	~~800 MW~~	Cancelled In Service - TBD	~~~ $ 800 Million~~	~~Coal~~	8
Wellington Development	Pennsylvania Greene County	525 MW CFB	Draft Air Permit (3/2005) In Service - 2007	$ 800 Million	Waste Coal	11
Reliant Energy	Pennsylvania Indiana	520 MW CFB	Operational (9/2004) In Service - 2004	$ 800 Million	Waste Coal	1, 2, 8, 12
EnviroPower	Pennsylvania Somerset	525 MW	Initiate - 2002 In Service - TBD	~ $525 Million	Coal	8
PA Energy Development Corp.	Pennsylvania Southwestern region	1,000 MW	Proposed (4/2004) In Service - TBD	~ $ 1 Billion	Coal	2
Robinson Power CO.	Pennsylvania Washington County	TBD	Proposed (4/2005) In Service - TBD	$400Million	Waste Coal	2
Santee Cooper	South Carolina Berkeley County	640 MW	Development (2/2004) In Service - 2007	$ 720 Million	Coal	1, 12, 2
LS Power Development	South Carolina Marion City	500-1,100 MW	Permitting (8/2002) In Service - 2006	~ $ 1 Billion	Coal	6, 11
Otter Tail Power Company	South Dakota Milbank	600 MW	Permitting (6/2005) In Service - 2011	$ 1 Billion	Coal	2, 11

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CME North America Merchant Energy	Tennessee Chattanooga	1000 MW	Proposed (9/2001) In Service - 2007	~ $ 1 Billion	Coal	8, 11, 12
~~Pickwick Power TVA~~	~~Tennessee Hardin County~~	~~100 MW CFB~~	Cancelled (1/2003) ~~In Service 2004~~	~~$100 Million~~	~~Coal~~	13, 11, 8, 12
Sepra Generation	Texas Bremond	600 MW	Proposal (7/2005) In Service - 2011	$800 Million	Lignite Coal	1
City Public Service Board of San Antonio	Texas Calaveras Lake	750 MW	Permitting (12/2004) In Service - 2009	$1 Billion	Coal	1, 11
LS Power Development	Texas Riesel	800 MW	Permitting (2/2005) In Service - 2009	$1 Billion	Coal PBR	12
~~San Antonio Public Service Bd.~~	~~Texas San Antonio~~	~~500 MW~~	Cancelled ~~In Service 2004~~	~~~ $500 Million~~	~~Coal~~	14
PacifiCorp	Utah Emery	850 MW	Development (8/2003) In Service - 2009	$800 Million	Coal	12, 2
Intermountain Power	Utah Delta	950 MW	Development (6/2005) In Service - 2008	$1.7 Billion	Coal	3, 4, 8, 12, 10, 20
Nevco Energy	Utah Sigurd	270 MW CFB	Proposed (6/2004) In Service - 2008	$350 Million	Coal	11
~~Duke Energy North America~~	~~Virginia Isle of Wright~~	~~700 MW Gasification~~	Cancelled (9/2002) ~~In Service 2008~~	~~$800 Million~~	~~Coal~~	1
LS Power Development	Virginia Sussex County	1,600 MW	Permitting (8/2002) In Service - 2005	~ $ 1.6 Billion	Coal	6, 8, 1
Dominion, AEP, Appalachian Power	Virginia Southwest	TBD	Proposed (2/2005) In Service - 2012	$1 Billion	Virginia Coal	2, 11

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Composite Power	Washington Richland	2500 MW Refurbish old site	Assessment (8/2001) In Service - TBD	~ $2.5 Billion	Coal	11
Energy Northwest	Washington Western Washington	600 MW IGCC	Proposal (7/2005) In Service - 2011	~ $600 Million	Coal	11
~~U.S. Electric Power~~ ~~Globaltex~~	~~Washington~~ ~~Whatcom County~~	~~249 MW~~	~~Cancelled (4/2003)~~ ~~In Service - 2004~~	~~~ $ 250 Million~~	~~Low-Sulfur Coal~~ ~~Vancouver~~	1, 3, 4, 8, 12
GenPower LLC Longview	West Virginia Monogalia County	660 MW	Permitting (11/2004) In Service - 2010	$940 Million	Coal	2, 11
Western Greenbrier CO-Generation / DOE	West Virginia Greenbrier County	85 MW Advanced CFB	DOE Approved - (7/2004) In Service - 2008	$215 Million	Waste Coal	1, 11
North American Power Group Ltd.	West Virginia Not yet located	300 MW	Proposal (2/2002) In Service - 2005	~ $300 Million	Coal	14
Anker Energy	West Virginia Upshur County	450 MW	On Hold - (9/2002) In Service - 2006	$ 600 Million	Central App. Coal & Waste Coal	1, 2, 12
Alliant Energy	Wisconsin Portage	500 MW	Considering (6/2005) In Service - 2010	~ $ 500 Million	Coal PBR	1, 9, 12
MidAmerican Energy	Wisconsin Cassville	200 MW	Proposal - (9/2002) In Service - TBD	~ $ 250 Million	Coal	8, 12
Wisconsin Energy & Madison Gas	Wisconsin Oak Creek	2 Plants (S-critical) 600 MW each	Development (6/2005) In Service - 2009-10	$ 2.5 Billion	Powder River Basin Sub-Bituminous	11, 1, 12, 2
Wisconsin Public Service Corp.	Wisconsin Wausau	500 MW	Construction (6/2005) In Service - 2008	$750 Million	Low-Sulfur Coal	1, 2, 11
North American Power Group	Wyoming Campbell County	300 MW	Construction (6/2005) In Service - 2008	$ 450 Million	Waste Coal	4, 6, 7, 12

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~~North American Power Group~~	~~Wyoming Campbell County~~	~~500 MW~~	Cancelled (2/2003) In Service - 2005	~~$ 750 Million~~	~~Powder River Basin Waste Coal~~	6, 12
Basin Electric Power Cooperative	Wyoming Gillette	250 MW	Proposed (1/2005) In Service - 2011	~$ 625 Million	Powder River Basin Coal	2, 7
Black Hills Corp.	Wyoming Gillette	90 MW	Operational (3/2003) In Service - 2003	$ 100 Million	Powder River Basin Sub-Bituminous	2, 4, 7, 12
Black Hills Corp.	Wyoming Gillette	100 MW	Development (6/2005) In Service - 2008	~ $ 160 Million	Powder River Basin Sub-Bituminous	2, 3, 4, 7, 12
DKRW	Wyoming Medicine Bow	350 MW & Fuels	Considering (3/2005) In Service - 2008	2.5 Billion	Wyoming Coal	1
American Electric Power	Undecided: OH, WV, and/or KY	2 - 600MW IGCC Plants	Proposed (6/2005) In Service - 2010	2.0 Billion	Coal	1, 11
FirstEnergy/Consol	Undecided PA or OH	TBD IGCC	Considering (3/2005) In Service - TBD	TBD	Coal	19
Westar Energy Inc.	Undecided	TBD	Considering (6/2005) In Service - 2012	TBD	Coal	2
Dominion Resources	Undecided	3 Plants 2,750 MW (total)	Initiate - TBD In Service - TBD	~ $ 3.3 Billion	Coal	7, 8

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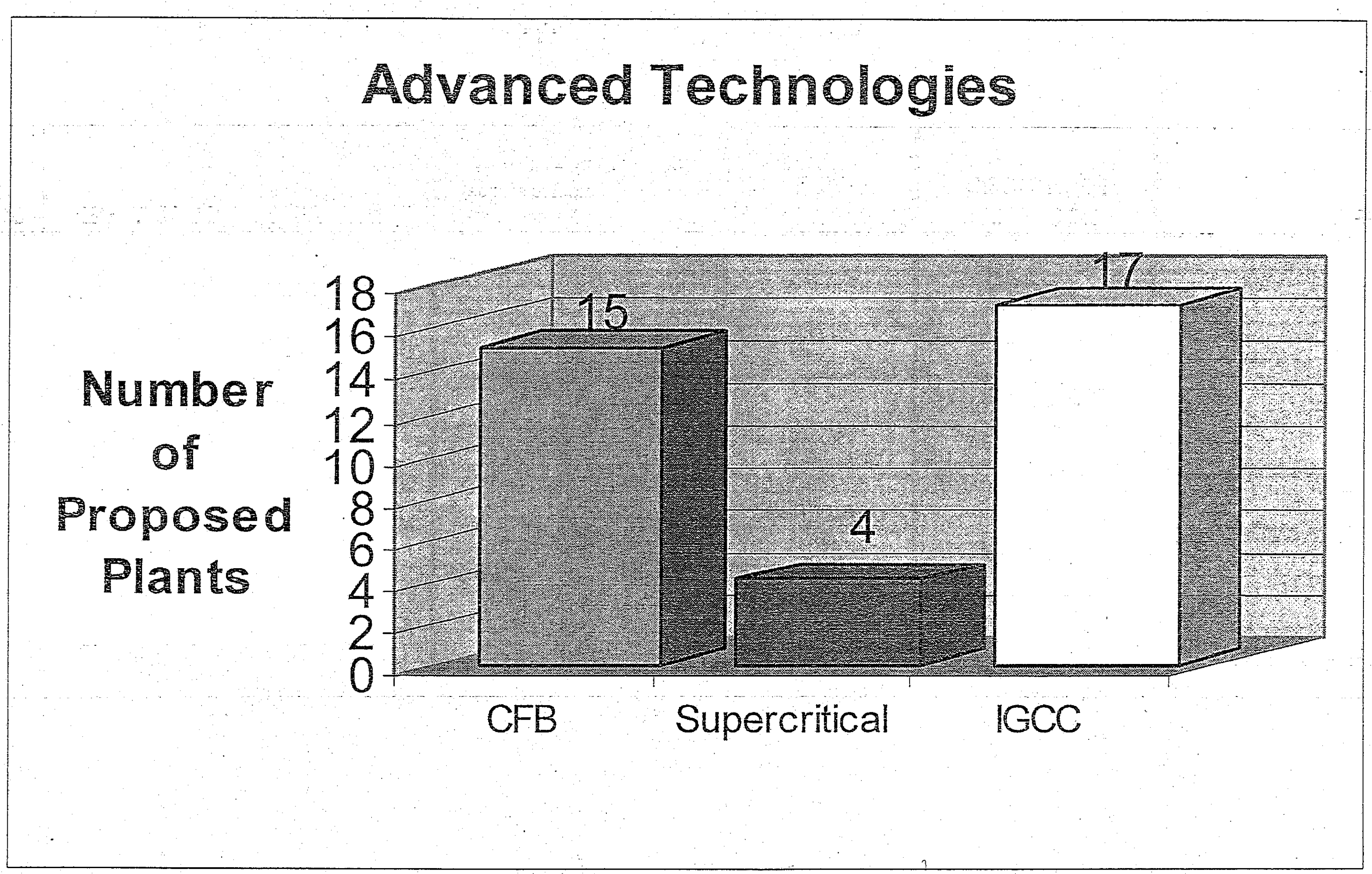

New Coal Fired Power Plant Projects

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NETL

NETL Contacts: Scott Klara, klara@netl.doe.gov
Erik Shuster, erik.shuster@sa.netl.doe.gov

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Polygeneration of SNG, Hydrogen, Power, and Carbon Dioxide from Texas Lignite

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David Gray
Salvatore Salerno
Glen Tomlinson

John J. Marano, Consultant

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Polygeneration of SNG, Hydrogen, Power, and Carbon Dioxide from Texas Lignite

Introduction

The intent of this study is to investigate the feasibility of siting a lignite conversion plant in Texas at the minemouth of the Wilcox lignite deposit. The concept is to coproduce at least three products: electric power, hydrogen or substitute natural gas (SNG), and carbon dioxide. The electric power would be sold to the grid, the hydrogen would be sent by pipeline to the Gulf Coast petroleum refineries, the SNG would be sold as a natural gas supplement, and the carbon dioxide would be pipelined to the West Texas oil fields for enhanced oil recovery (EOR). EOR provides an economically attractive option for sequestering CO_2, and thus reducing greenhouse gas emissions from the lignite conversion. If natural gas prices continue to remain high in the future, there may be an opportunity for petroleum refiners to use low cost Texas lignite in place of natural gas to provide the hydrogen necessary for their refining operations. Also, lignite could be used to produce SNG as a natural gas supplement, and electric power could also be generated from the lignite and dispatched to the Texas grid. In the longer term, since SNG uses the same infrastructure as natural gas, SNG could be an attractive alternative as a hydrogen carrier for fuel cell based transportation systems. Finally, the West Texas oil fields continue to need carbon dioxide for EOR applications and carbon dioxide produced as a by product of Texas lignite conversion represents a potentially valuable resource close to the oil fields.

Site Selection

In the 1970s, concerns over a potential shortage of natural gas fostered considerable interest in the production of substitute natural gas from coal. A number of large-scale demonstration projects were planned. Of these projects, only one was ever built, in Beulah, North Dakota. The increased availability of North American natural gas in the 1980s and 1990s ended interest in large-scale production of SNG from coal. However, small-scale SNG production from LPG and naphtha has found a niche market in Japan and elsewhere. These systems provide back-up fuel for natural gas based power generation.

The increased demand for natural gas has resulted both in higher gas prices and more gas imports, a trend that is anticipated to continue. The Energy Information Administration (AEO 2004) predicts the wellhead natural gas price will rise to between \$4.40 and \$4.94 per million BTU by 2025, up from a 2002 price of \$2.95. Much of the predicted future demand is anticipated to be supplied by imports of liquefied natural gas (LNG). Recent spot prices for natural gas have been volatile, ranging between \$1.70 and \$8.00 per million BTU and have averaged \$5.81 per million BTU through August 2004. Therefore, the economics of SNG production may again be attractive, particularly if produced from low cost feedstocks and co-producing high valued by-products such as electricity.

Dakota Gasification Company's Beulah plant still produces about 170 million SCFD of SNG from lignite. In addition, it has expanded operations to co-produce ammonia, ammonium sulfate, phenol, and cresylic acid. In 2000, the plant began exporting carbon dioxide for use in enhanced oil recovery. Currently, about 95 million SCFD of CO_2 produced at the plant is transported via a 205 miles long pipeline to EnCana Corporation's Weyburn oil field in southern Saskatchewan. The CO_2 is used for tertiary oil recovery, resulting in 5,000 bbl/day of incremental oil production or an additional 130 to 140 million barrels of oil over the life of the project. The initial investment for this project was $1.3 billion (Canadian) by EnCana for field facilities and $100 million (U.S.) by Dakota Gasification for the pipeline and supporting facilities. Annual net revenue generated by the sale of the CO_2 is between $15 and 18 million. The Weyburn field is the subject of a long-term monitoring program to assess the final deposition of the CO_2 being injected in this project.

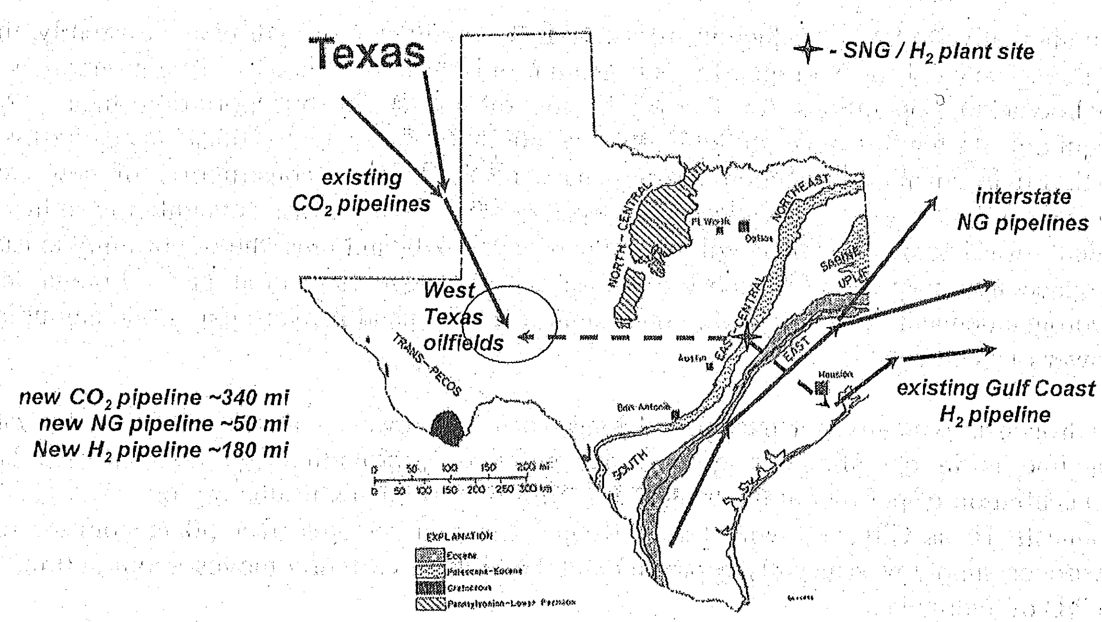
An alternative to SNG production from coal is the production of hydrogen. Currently, there is strong demand for hydrogen for petroleum refining, where it is used in hydrotreating and hydrocracking operations for the production of low sulfur transportation fuels. New requirements for ultra-low sulfur gasoline (2005) and diesel fuel (2008) mandated by the U.S. Environmental Protection Agency have resulted in the construction of new steam methane reformers for the production of hydrogen from natural gas. It is anticipated that the trend toward zero sulfur fuels will continue beyond 2010, and thus, the opportunity exists to produce hydrogen from low-cost coals as an alternative to natural gas. Longer term, hydrogen demand within the U.S. could significantly expand if hydrogen is one day used to power fuel cell vehicles.

Hydrogen is typically not transported long distances; however, a 300 mile long hydrogen pipeline is in operation along the U.S. gulf coast, providing hydrogen to the large concentration of petroleum refineries and petrochemical plants in this region. The pipeline connects Texas City, TX with Baton Rouge, LA, and services over 50 customers. The hydrogen supply was recently expanded and the pipeline currently moves about 560 million SCFD of hydrogen.

One potential drawback to the production of SNG or hydrogen from coal is the co-production of large quantities of CO_2, a greenhouse gas. Geological sequestration is one option for mitigating CO_2 emissions from coal conversion. This may be an especially attractive option if the CO_2 is used for enhanced oil recovery as is being done at the Weyburn field using CO_2 produced at Dakota Gasification. There are a number of other locations within the U.S. where low-priced coals are located near oil fields that currently employ CO_2 EOR, including Wyoming and West Texas. The Permian Basin in West Texas currently utilizes about 1,200 million SCFD of CO_2 and is the largest CO_2 EOR operation in the world. The bulk of the CO_2 currently used there is produced from natural CO_2 reservoirs located in northern New Mexico and southern Colorado and shipped via pipeline to West Texas. The remaining CO_2 comes from gas plants located in West Texas. About 160,000 incremental barrels of oil are produced per day due as a result of CO_2 EOR. The Wyoming oil fields currently utilize between 150 and 175 million SCFD, all of it supplied by gas plants. In addition to the Weyburn field in Saskatchewan, oil production in the Williston basin of North Dakota could be improved through CO_2 EOR, though no projects are currently in operation there. The production and reserves of surface-mineable coal located near these oil fields are given below:

	Production MM tons	Reserves MM tons	Price $/ton
Texas Lignite	50	10,000	14.00
North Dakota Lignite	30	7,200	8.50
WY Sub-bituminous	380	22,000	6.50

For this study, the coal conversion plant was sited in Texas at a minemouth location above the Wilcox lignite seam. This is shown below:



The Texas site was selected because it fulfilled all major requirements. It is roughly 340 miles from the West Texas oil fields, 20 miles from interstate natural gas pipelines that run to the U.S. East Coast and Midwest, and 180 miles from the existing U.S. gulf coast hydrogen pipeline. In addition, electric power is already produced at minemouth locations along the seam. The only drawback of Texas lignite relative to the other coals identified above is its relative higher price. Other locations such as North Dakota and Wyoming may have better economics but are not located in high hydrogen demand areas of the U.S. The analysis presented below for SNG would be generally applicable to these other locations; however, product yields and cost would be different.

Plant Designs

This analysis has investigated two overall conceptual configurations. The first of these uses Texas Lignite to produce electric power, SNG, and carbon dioxide in a polygeneration facility. The second polygeneration configuration uses the Texas lignite to produce electric power, hydrogen, and carbon dioxide.

Conversion of Texas lignite using gasification technology presents some challenges because of the high moisture content of the as-received (AR) coal. The AR lignite contains 30 weight percent moisture and 11.8 percent oxygen (see Table 1). Because of this the calorific value of the coal is low at 7868 Btu per pound on a high heating value (HHV) basis.

Seven gasification systems were examined to convert the lignite into synthesis gas. These are listed in Table 2. The single-stage slurry feed system with heat recovery represents a GE/Texaco type process. This gasifier type is in operation at the Polk Power Station in Florida. Feeding the coal to the gasifier in this system requires that the coal be slurried with water. Assuming that the slurry can contain 66 percent lignite by weight and, because the lignite already contains 30 percent moisture, the overall solids content of the slurry is only 46 percent by weight. This means that 54 weight percent of the input to the gasifier is water. This results in a total carbon content in the feed slurry of only 29 weight percent. Because of this low carbon content and high water content, the overall clean cold gas efficiency of the gasification system is only 60 percent on an HHV basis. This means that only 60 percent of the energy content of the input lignite resides in the clean synthesis gas. It is assumed that the capacity factor for this system would be 85 percent. That is, the gasifier is on stream

Table 1. Wilcox Lignite Analysis

	AF	MAF	As Fed	MF	AR
Carbon	58.14	72.47	55.38	63.19	44.24
Hydrogen	4.89	6.09	4.65	5.31	3.72
Nitrogen	0.96	1.2	0.92	1.05	0.73
Sulfur	0.77	0.96	0.73	0.84	0.59
Oxygen	15.47	19.28	14.73	16.81	11.77
Mineral/Matter	11.78	–	11.22	12.80	8.96
Moisture	8.00	–	12.36	14.10	30
Total	**100.00**	**100**	**100.00**	**114.10**	**100.00**
HHVBTU#	10341	12890	9851	11240	7868

producing synthesis gas for 310 days per year. Also, it is assumed that the carbon utilization is 95 percent. That is, 5 percent of the input carbon in the lignite resides in the slag.

Table 2. Summary of Cases Analyzed

Gasifier Type Case Number	Single-Stage Slurry Feed Heat Recovery –	Single-Stage Slurry Feed Quench –	Two-Stage Slurry Feed Heat Recovery and Quench	Single-Stage Dry Feed Heat Recovery –	Single-Stage Dry Feed Quench	Single-Stage Dry Feed Quench Advanced
Hydrogen/Power/CO_2	√	√	√	√	√	√
SNG/Power/CO_2	√	√	√	√	√	√
Capacity Factor %	85	85	85	85	85	90
Carbon Utilization %	95	95	95	95	95	99
Percent Solids in Slurry	46	46	46	NA	NA	NA
Feed Coal Moisture Wt %	30	30	30	12	12	8
Cold Gas Efficiency (% HHV)	60	60	69	77.5	77.5	80

The single-stage slurry gasifier with quench represents a GE/Texaco system with full quench in place of a radiant gas cooler for heat recovery. Because the lignite is fed using a water slurry, the same issues pertain as in the prior case.

The two-stage slurry feed gasifier represents a ConocoPhillips E-Gas type system. This gasifier is operating at Wabash, Indiana. In this system the coal is injected using a water slurry into two stages of the gasifier. In the first stage the coal slurry is gasified with oxygen and the hot gases from this stage rapidly dry the second stage coal slurry. The unconverted char is then separated from the gasifier effluent and this dried char is recycled back to the first stage. Therefore this gasifier system can be thought of as being intermediate between a single stage slurry system and a dry feed system. This is exemplified by the much higher clean cold gas efficiency (69 percent versus 60 percent) of this system. A preliminary analysis of both a heat recovery and a quench version of this two-stage system was undertaken.

Three dry feed gasification systems were analyzed. The single-stage dry feed heat recovery case represents a Shell type system with a waste heat boiler. This system is operating at the NUON IGCC plant in the Netherlands. In this system the as-received lignite must be dried before feeding to the lock hoppers. If the lignite is not dried it will bridge and block the pressurized lock hoppers. In this analysis it is assumed that the lignite is dried from 30 to 12 weight percent moisture. The resulting carbon in the feed lignite is then 55.38 percent (see Table 1).

The single-stage dry feed quench system analyzed represents a Shell type gasifier but with the waste heat boiler section eliminated and replaced by full water quench of the gasifier effluent. This quench configuration is not commercially available but, because the system is much less expensive without the waste heat boiler it is assumed that it could be available if it proved suitable for certain applications. In these two dry feed Shell type gasifiers, cooled synthesis gas is recycled to the gasifier exit to cool the effluent synthesis gas to below the ash fusion temperature before the gas enters the waste heat boiler. In these dry feed systems the clean cold gas efficiency is increased to 77.5 percent on an HHV basis. It was assumed that the capacity factor remained at 85 percent and the carbon utilization remained at 95 percent.

The single-stage dry feed advanced quench gasification system analyzed in this study represents a GSP type gasifier. The GSP process was formerly known as the Babcock Borsig Power (BBP) Noell process. Future Energy GmbH acquired the intellectual property rights, the test plant facilities, real estate and buildings, and the entire patent stock from the insolvent BBP in December 2002. In Schwarze Pumpe Germany, the GSP process was used to gasifier lignite until 1991. This gasifier has a capacity of about 700 tons per day (130 MW thermal). Currently it is being used to gasify waste oils to produce synthesis gas for a methanol plant.

The GSP gasifier is a dry feed system. It is an oxygen-blown entrained gasifier with a so called "cooling screen" wall. This concept is similar to that of the Shell process where a membrane wall with pressurized water or steam is used to cool the gasifier inside surface so that a constantly forming liquid slag layer forms the refractory lining. This is different from the other gasifier systems like GE/Texaco and E-Gas where a brick refractory lining is used. In this case the lignite feed is dried to 8 weight percent moisture before being sent to the pressurized lock hoppers. The resulting carbon content of the feed is then 58.14 percent. The clean cold gas efficiency in this case is 80 percent. It is assumed in this case that the capacity factor has increased to 90 percent and the carbon utilization has increased to 99 percent.

After an initial screening study of the various gasification systems it was concluded that, because of the low cold gas efficiency of the single-stage slurry feed gasifiers when used to gasify the lignite, they were not suitable for processing this coal. However, the slurry feed gasifiers could be suitable for gasifying high moisture low rank coals if it were possible to remove the inherent moisture by drying and then to slurry the dried coal with water and feed this slurry to the gasifier before the coal could reabsorb the moisture. Because of this uncertainty, only six cases were analyzed in detail and these are shown in Table 3. The two-stage slurry quench (E-Gas type), the single-stage dry feed quench (Shell type), and the single-stage advanced dry feed quench (GSP type) gasifiers were analyzed in the two configurations to produce either SNG or hydrogen, along with power and carbon dioxide.

Production of SNG, Carbon Dioxide, and Power

Figure 1 shows the schematic of the three cases that convert the lignite into SNG, power, and carbon dioxide. In the case using the two-stage slurry gasifier with quench (Case 1S) the as-received lignite is slurried with water and fed with oxygen into the gasifier. In the two cases where the dry feed gasifiers are used (Cases 2S and 3S) the lignite is dried under nitrogen using some of the fuel gas and the dried lignite is pneumatically conveyed to the gasifier using either nitrogen or carbon dioxide. The raw synthesis gas after water quench is sent to a raw gas shift unit where the hydrogen to carbon monoxide molar ratio is adjusted to three to one to be compatible with methanation. The shift effluent is cooled and passed to the activated carbon reactor to remove mercury. The synthesis gas is then sent to sulfur removal where a concentrated stream of hydrogen sulfide is produced. This is sent to a Claus SCOT combination for sulfur recovery. After sulfur removal the gas is sent to a bulk carbon dioxide removal system. The recovered carbon dioxide is then dehydrated and compressed

Table 3. Cases Analyzed

Case	Description
1 S	Two-stage slurry quench-SNG/Power/CO_2
2 S	Single-Stage dry quench-SNG/Power/CO_2
3 S	Advanced single-stage dry quench-SNG/Power/CO_2
1 H	Two-stage slurry quench H_2/Power/CO_2
2 H	Single-stage dry quench H_2/Power/CO_2
3 H	Advanced single-stage dry quench-H_2/Power/CO_2

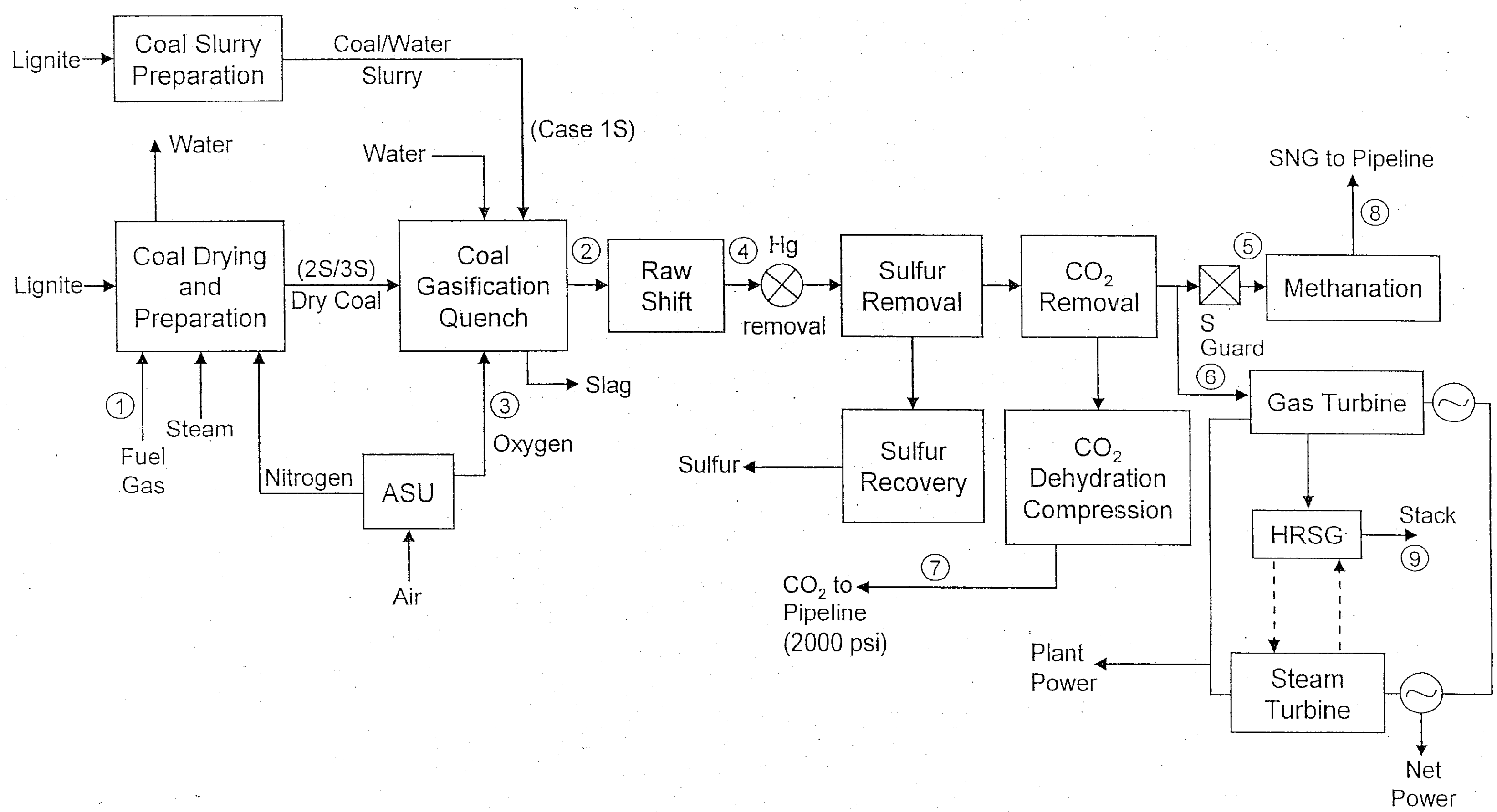


Figure 1. Texas Lignite to Power and SNG

to 2000 psi and sent to a pipeline. To protect the methanation catalyst, the synthesis gas with sulfur and carbon dioxide removed is sent to a sulfur polishing reactor to remove the last traces of hydrogen sulfide before being sent to the three stage methanation reactor. In this reactor the carbon monoxide and hydrogen are combined to produce methane. The SNG from the methanation reactor, at about 20 bars, is then sent to battery limits to be compressed for delivery to the natural gas pipeline. Some of the synthesis gas exiting the bulk carbon dioxide removal system is sent to a gas turbine where electric power is generated. The hot effluent from the gas turbine is sent to a heat recovery seam generator (HRSG) where the high pressure steam is used in a steam turbine to generate additional electric power. Some of this power is used in the plant and the net power is sold.

Table 4 summarizes the results of the three SNG cases. In Case 1S, the synthesis gas is produced using a two-stage slurry feed quench gasification system. Feed rate is 7,500 TPD of as-received lignite containing 30 weight percent moisture. The products from this plant are 32 MMSCFD of SNG, 7,753 TPD of carbon dioxide, and 255 MW of net electric power. The overall HHV efficiency of the process from lignite to products is 44.6 percent. The capital cost of the plant is estimated to be $760 MM (see Table 5 for the capital cost breakdown). The operating and maintenance cost, less the lignite, is estimated to be $39 MM per annum and the lignite cost is $33 MM per annum. The lignite is assumed to cost $14 per ton on an as-received basis. The assumed capacity factor for the plant is 85 percent. The required selling price (RSP) of the SNG was calculated using a discounted cash flow (DCF) analysis with the financial parameters shown in Table 6. Because three products are produced from the plant, power, carbon dioxide and SNG, it was necessary to fix the value of two of the products and calculate the RSP of the third. It is assumed that the value of the electric power is $35.6 per MWH and the value of the carbon dioxide is $12 per ton. With these values and the financial parameters assumed in the DCF analysis, the RSP of the SNG for this case is calculated to be $6.90/MMBTU.

In Case 2S, the synthesis gas is produced using a single-stage dry feed quench gasification system. The lignite dried to 12 weight percent moisture is conveyed to the high pressure gasifier using carbon dioxide as carrier gas so that nitrogen will not dilute the SNG product. The dried lignite feed rate is 5,990 ton per day (TPD). The products from this plant are 34 MMSCFD of SNG, 7,418 TPD of carbon dioxide, and 236 MW of net electric power. The assumed capacity factor for the plant is 85 percent. The overall HHV efficiency of the process from lignite to products is 45.3 percent. The capital cost of the plant is estimated to be $743 MM (see Table 5 for the capital cost breakdown). The operating and maintenance cost, less the lignite, is estimated to be $38 MM per annum and the lignite cost is $33 MM per annum. Because the lignite is dried to 12 percent moisture the cost of the lignite on an as-fed basis is now $17.53 per ton. The required selling price (RSP) of the SNG was calculated using a discounted cash flow (DCF) analysis with the financial parameters shown in Table 6. As in Case 1S, it is assumed that the value of the electric power is $35.6 per

Table 4. Summary of Results: SNG and Power

	Two-Stage/Slurry/Q Case 1S	Single-Stage/Dry/Q Case 2S	Single-Stage/Dry/Q/Advanced Case 3S
Coal Input (TPD AF)	7500	5990	5707
SNG Out (MMSCFD)	32	34	39
Power Net (MW)	255	236	244
Overall Efficiency (% HHV)	44.6	45.3	49.4
Capital ($ MM)	760	743	734
O & M ($ MM)	39	38	38
Coal Cost (MM$/Yr) ($/T)AF	33/14	33/17.53	35/18.4
CO_2 Value ($/T)	12	12	12
CO_2 Captured (TPD)	7753	7418	7724
Power Value ($/MWH)	35.6	35.6	35.6
RSP SNG ($/MMBtu) (HHV)	6.90	6.73	5.00

Table 5. Capital Cost Summary: SNG and Power

	$MM (2004)		
	Case 1S	Case 2S	Case 3S
Coal Handling/Drying	28	47	45
Gasification	102	87	70
Air Separation	83	75	76
Sulfur Removal/Recovery	22	22	23
Shift	22	20	20
CO_2 Removal/Compression	43	47	46
Methanation	31	33	36
Power Generation/Distribution	191	182	189
WW Treatment	13	13	13
Balance of Plant	44	40	41
Total Installed Cost	**579**	**566**	**559**
Home Office (8.4%)	49	48	47
Fee (2%)	11	11	11
Contingency (15%)	96	94	93
Total Plant Cost	**735**	**719**	**710**
Total Capital (Inc. ND Capital)	**760**	**743**	**734**

Table 6. Discounted Cash Flow Analyses Assumptions

Initial Plant Output 50% (Year 1) 90% (Year 2)

Debt: Equity = 67:33

Required Selling Price (RSP) in constant dollars necessary for 15% ROE (Current $)

Debt: 16 years @ 8% interest

General inflation 3%

Escalation in accordance with EIA projects

Depreciation 16 years with double declining balance

Federal and state income tax (Fed 34%) (State 6%)

Local tax and insurance 2% of depreciable capital

Project life 25 years

MWH and the value of the carbon dioxide is $12 per ton. With these values and the financial parameters assumed in the DCF analysis, the RSP of the SNG for this case is calculated to be $6.73/MMBTU.

In Case 3S, the synthesis gas is produced using a single-stage advanced dry feed quench gasification system. The stream numbers on Figure 1 refer to the material balance for this case. The material balance is shown for selected stream flows for this case and is summarized in Table 7. Again the coal is conveyed into the gasifier using carbon dioxide and the feed rate is 5,707 TPD of dried lignite containing 8 weight percent moisture. The products from this plant are 39 MMSCFD of SNG, 7,724 TPD of carbon dioxide, and 244 MW of net electric power. The assumed capacity factor for the plant is 90 percent and the carbon utilization is assumed to be 99 percent. The overall HHV efficiency of the process from lignite to products is 49.4 percent. The capital cost of the plant is estimated to be $734 MM (see Table 5 for the capital cost breakdown). The operating and maintenance cost, less the lignite, is estimated to be $38 MM per annum and the lignite cost is $35 MM per annum. Because the lignite is dried to 8 percent moisture the cost of the lignite on an as-fed basis is now $18.40 per ton. The required selling price (RSP) of the SNG was calculated using a discounted cash flow (DCF) analysis with the financial parameters shown in Table 6.

As in Case 1S, it is assumed that the value of the electric power is $35.6 per MWH and the value of the carbon dioxide is $12 per ton. With these values and the financial parameters assumed in the DCF analysis, the RSP of the SNG for this case is calculated to be $5.00/MMBTU.

Production of Hydrogen, Carbon Dioxide and Power

Figure 2 shows the schematic of the three cases that convert the lignite into hydrogen, power, and carbon dioxide. In the case using the two-stage slurry gasifier with quench (Case 1H), the as-received lignite is slurried with water and fed with oxygen into the gasifier. In the two cases where the dry feed gasifiers are used (Cases 2H and 3H), the lignite is dried under

Table 7. Power and SNG Production Noel Quench Gasifier (Case 3S)

Selected Flows, Pound Moles/Hour

	1 Fuel Gas To Drying	2 Quenched Output	3 Oxygen To Gasifier	4 Shifted Gas	5 Clean Gas To Methatn	6 Turbine Fuel	7 CO2 To Pipeline	8 SNG To Pipeline	9 Stack From HRSG
CH4	0.1	2		2	1	0.8		4,076	0
H20	0	43,842		0	0	0		0	10,218
H2	1,135	9,962		24,019	12,427	10,217		443	0
CO	380	22,064		8,006	4,159	3,419		2	0
CO2	8	2,044		16,101	89	73	14,629	212	3,493
N2	11	240	101		125	102		126	94,850
H2S		114		114					0
NH3									0
O2			10,138						12,818
Total	1,535	78,267	10,239	48,243	16,801	13,813	14,629	4,859	121,380
T, Deg F	309	400	555	110	309	309		488	260
P, atm	1.0	30.0	30.6	27.1	25.0	34.7	136	20.0	1.00

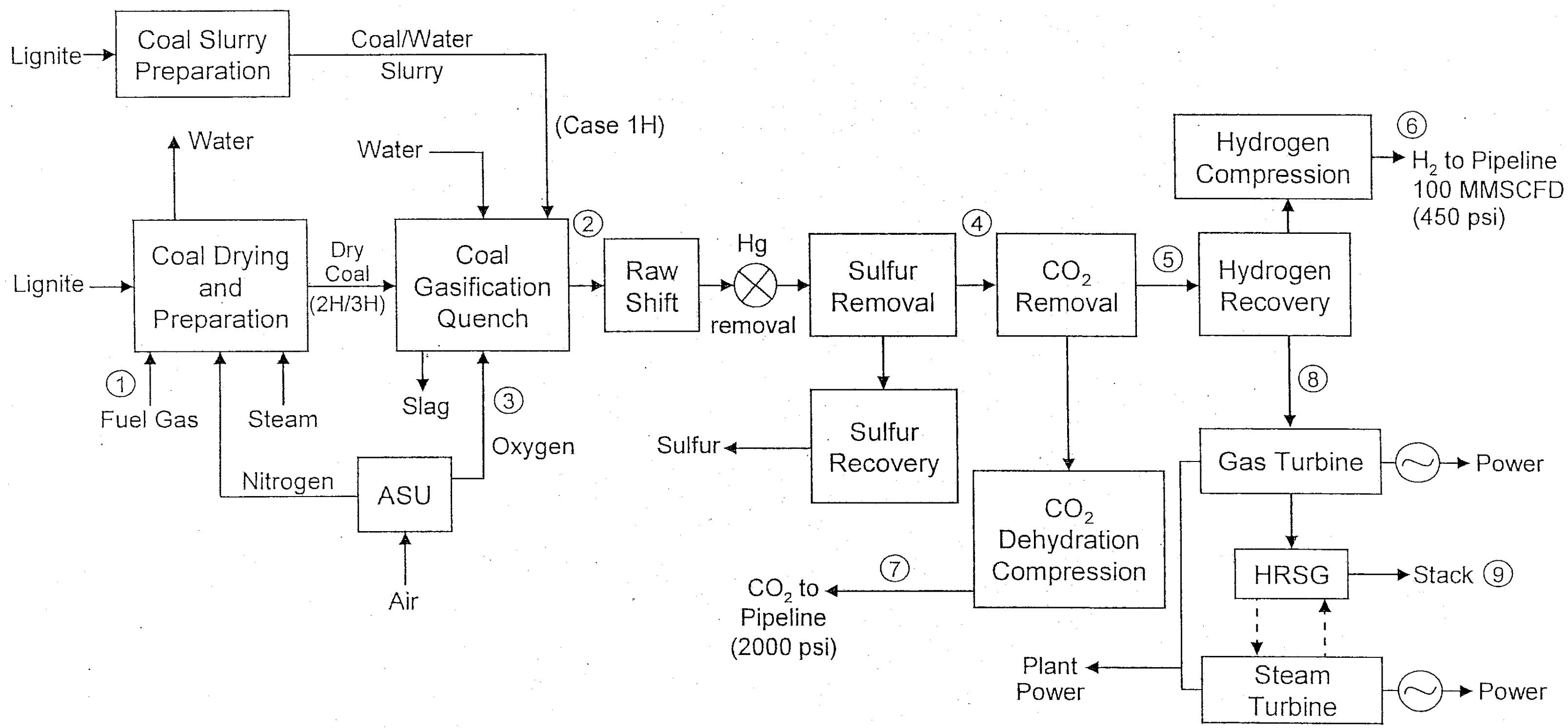


Figure 2. Lignite to Electric Power and Hydrogen

nitrogen using some of the fuel gas and the dried lignite is pneumatically conveyed to the gasifier using nitrogen. The raw synthesis gas after water quench or scrub is sent to a raw gas shift unit where much of the carbon monoxide is converted into hydrogen. The shift effluent is cooled and passed to the activated carbon reactor to remove mercury. The synthesis gas is then sent to sulfur removal where a concentrated stream of hydrogen sulfide is produced. This is sent to a Claus SCOT combination for sulfur recovery. After sulfur removal, the gas is sent to a bulk carbon dioxide removal system. The recovered carbon dioxide is then dehydrated and compressed to 2000 psi and sent to a pipeline. The synthesis gas with sulfur and carbon dioxide removed is sent to a polymer membrane separation system followed by a PSA unit where the required amount of hydrogen is removed. A membrane system is used in this case to maintain the system pressure of the remaining synthesis gas that will be used for power generation. This synthesis gas is sent to a gas turbine where electric power is generated. The hot effluent from the gas turbine is sent to a heat recovery seam generator (HRSG) where the high pressure steam is used in a steam turbine to generate additional electric power. Some of this power is used in the plant and the net power is sold.

Table 8 summarizes the results for the three hydrogen production cases. In Case 1H, the synthesis gas is produced using a two-stage slurry feed quench gasification system. Feed rate is 6,852 TPD of as-received lignite containing 30 weight percent moisture. The products from this plant are 100 MMSCFD of hydrogen, 9,202 TPD of carbon dioxide, and 224 MW of net electric power. The overall HHV efficiency of the process from lignite to products is 46.5 percent. The capital cost of the plant is estimated to be $709 MM (see Table 9 for the capital cost breakdown). The operating and maintenance cost, less the lignite, is estimated to be $36 MM per annum and the lignite cost is $30 MM per annum. The lignite is assumed to cost $14 per ton on an as-received basis. The assumed capacity factor for the plant is 85 percent. The RSP of the hydrogen was calculated using a DCF analysis with the financial parameters shown in Table 6. As in the previous cases, it is assumed that the value of the electric power is $35.6 per MWH and the value of the carbon dioxide is $12 per ton. With these values and the financial parameters assumed in the DCF analysis, the RSP of the hydrogen for this case is calculated to be $5.94/MMBTU or $0.80 per kilogram.

In Case 2H, the synthesis gas is produced using a single-stage dry feed quench gasification system similar to Case 2S except that nitrogen is used to convey the coal to the gasifier. Feed rate is 5,158 TPD of dried lignite containing 12-weight percent moisture. The products from this plant are 100 MMSCFD of hydrogen, 8,468 TPD of carbon dioxide, and 189 MW of net electric power. The assumed capacity factor for the plant is 85 percent. The overall HHV efficiency of the process from lignite to products is 47.1 percent. The capital cost of the plant is estimated to be $666 MM (see Table 9 for the capital cost breakdown). The operating and maintenance cost, less the lignite, is estimated to be $34 MM per annum and the lignite cost is $28 MM per annum. Because the lignite is dried to 12-percent moisture the cost of the lignite on an as-fed basis is now $17.53 per ton. The RSP of the hydrogen was calculated using a DCF analysis with the financial parameters shown in Table 6. As in Case 1H, it is assumed that the value of the electric power is $35.6 per MWH and the value

Table 8. Summary of Results: Hydrogen and Power

	Two-Stage/ Slurry/Q Case Number 1H	Single-Stage/ Dry/Q Case Number 2H	Single-Stage/ Dry/Q/Advanced Case Number 3H
Coal Input (TPD AF)	6852	5158	4665
Hydrogen Out (MMSCFD)	100	100	100
Power Net (MW)	224	189	193
Overall Efficiency (% HHV)	46.5	47.1	49.2
Capital ($ MM)	709	666	650
O & M ($ MM/Yr) (less coal)	36	34	34
Coal Cost ($MM/YR)/($/T/AF)	30/14	28/17.53	28/18.4
CO_2 Value ($/T)	12	12	12
CO_2 Captured (TPD)	9202	8468	8279
Power Value ($/MWH)	35.6	35.6	35.6
RSP Hydrogen ($/MMBtu) (HHV)	5.94	6.25	5.20
RSP Hydrogen ($/kg)	0.80	0.84	0.70

of the carbon dioxide is $12 per ton. With these values and the financial parameters assumed in the DCF analysis, the RSP of the hydrogen for this case is calculated to be $6.25/MMBTU or $0.84 per kilogram.

Table 9. Capital Cost Summary: Hydrogen and Power

	($ MM 2004)		
	Case 1H	**Case 2H**	**Case 3H**
Coal Handling/Drying	27	50	47
Gasification	93	75	70
Air Separation	77	65	65
Sulfur Removal/Recovery	22	21	21
Shift	20	18	18
CO_2 Removal/Compression	50	49	46
Hydrogen Recovery	16	16	16
Power Generation/Distribution	182	164	164
WW Treatment	14	14	14
Balance of Plant	39	36	34
Total Installed Cost	**540**	**508**	**495**
Home Office (8.4%)	45	43	42
Fee (2%)	11	10	10
Contingency (15%)	89	84	82
Total Plant Cost	**685**	**645**	**629**
Total Capital (Inc. ND Capital)	**709**	**666**	**650**

In Case 3H, the synthesis gas is produced using a single-stage advanced dry feed quench gasification system. The stream numbers on Figure 2 refer to the material balance for this case. The material balance is shown for selected stream flows for this case and is summarized in Table 10. Feed rate is 4,665 TPD of dried lignite containing 8 weight percent moisture. The products from this plant are 100 MMSCFD of hydrogen, 8,279 TPD of carbon dioxide, and 193 MW of net electric power. The assumed capacity factor for the plant is 90 percent and the carbon utilization was assumed to be 99 percent. The overall HHV efficiency of the process from lignite to products is 49.2 percent. The capital cost of the plant is estimated to be $650 MM (see Table 9 for the capital cost breakdown). The operating and maintenance cost, less the lignite, is estimated to be $34 MM per annum and the lignite cost is $28 MM per annum. Because the lignite is dried to 8 percent moisture the cost of the lignite on an as-fed basis is now $18.40 per ton. The RSP of the hydrogen was

Table 10. Power and Hydrogen Production Noel Quench Gasifier (Case 3H)

Selected Flows, Pound Moles Per Hour

	1	2	3	4	5	6	7	8	9
	Fuel Gas To Drying	Quenched Output	Oxygen To Gasifier	Shifted Gas	Clean Gas To H2 Rec	Recovered Hydrogen	CO2 To Pipeline	Turbine Fuel	Stack From HRSG
CH4	0.2	2		2	2			2	0
H2O	7	36,368		0	67			60	11,220
H2	1,239	8,914		23,531	23,414	11,019		11,155	0
CO	294	17,559		2,941	2,938			2,645	0
CO2	14	1,203		15,820	140		15,679	126	2,773
O2			8,376		0			0	13,499
N2	220	2,200	84	2,200	2,200			1,980	96,116
H2S		94		94					0
NH3									0
Total	1,774	66,340	8,460	44,589	28,762	11,019	15,679	15,969	123,608
T, Deg F	309	398	555	110	85	282		100	260
P, atm	1.0	30.0	30.6	27.1	27.1	30.6	136	1.0	1.0

calculated using a DCF analysis with the financial parameters shown in Table 6. As in Case 1H, it is assumed that the value of the electric power is $35.6 per MWH and the value of the carbon dioxide is $12 per ton. With these values and the financial parameters assumed in the DCF analysis, the RSP of the hydrogen for this case is calculated to be $5.20/MMBTU or $0.70 per kilogram.

Hydrogen Cost Compared to Natural Gas Costs

Figure 3 shows the impact of natural gas prices on the resulting cost of hydrogen from steam methane reforming. If the feed natural gas price to the steam methane reformer (SMR) is $3.00/MMBTU then the resulting cost of the hydrogen produced would be about $5.50/MMBTU or $0.74/KG. If the natural gas price was $4.00/MMBTU then the resulting cost of the hydrogen from the SMR would be about $6.75/MMBTU (HHV basis) or $0.91/KG. This analysis has estimated that the cost of producing hydrogen from Texas lignite is in the range of $5.20-$6.25/MMBTU. This is assuming that the plants are configured as described to coproduce electric power and carbon dioxide for sales. These costs of hydrogen would be equivalent to using steam methane reforming for natural gas prices of between $3 and $4.00/MMBTU. EIA is forecasting that natural gas prices will be in the range $4.50-$5.00/MMBTU by 2025 but spot natural gas process for 2004 have been much higher in the range $5.75 to $6.50/MMBTU with expectations that they may well rise to above $7.00/MMBTU during 2005.

This indicates that producing hydrogen from Texas lignite at the mine mouth and pipelining this hydrogen to Gulf Coast refineries could be an attractive proposition.

Impact of the value of the Carbon Dioxide

In this study it was assumed that the carbon dioxide was valued at $12 per ton. This is equivalent to $0.70 per thousand cubic feet about midway in the usual range of carbon dioxide prices for EOR. If the carbon dioxide could only command a lower value, then the required selling prices of the other co products would have to be increased to realize the annual revenue requirement for the plant. However, it takes capital and energy to capture, dehydrate, and compress the carbon dioxide. In the configuration that produces power, SNG, and carbon dioxide, it would not be economic to produce carbon dioxide as a co product for sale if the value of the carbon dioxide were less than $5.50 per ton. Similarly, for the plant producing power, hydrogen and carbon dioxide, it would not be economic to produce carbon dioxide as a co product for sale if the value of the carbon dioxide were less than $7.75 per ton. Therefore, a value of $12 per ton makes it worthwhile to recover the carbon dioxide for sale.

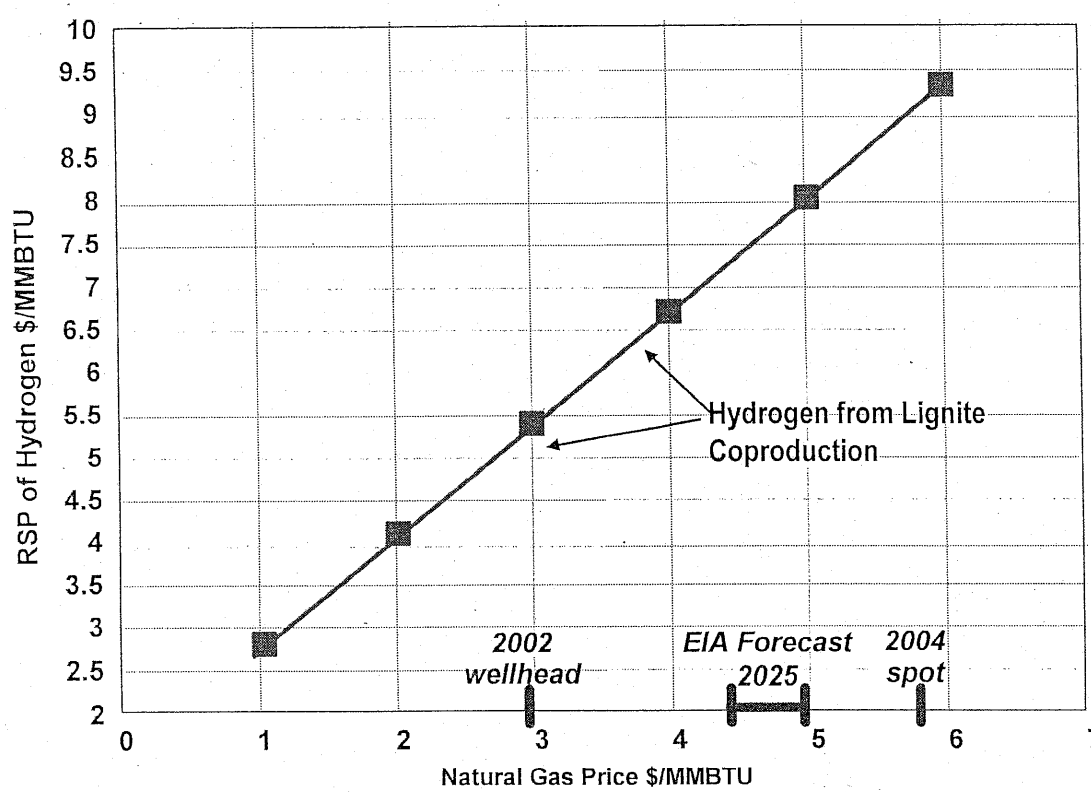


Figure 3. Hydrogen Cost versus Natural Gas Price from Steam Methane Reforming

Conclusions

This feasibility study has shown that siting a mine mouth Lignite fed gasification plant in Texas to produce hydrogen, SNG, electric power, and carbon dioxide could be economically feasible in an era of high natural gas prices.

Because of the high moisture content of the lignite the choice of gasification system becomes an important issue. If the as-received lignite is used directly, systems that use water slurry to feed the coal into the gasifier are penalized because of the very low carbon content of the resulting slurry. It may be possible to dry the lignite to a low moisture content, maybe 10 percent moisture, and then to slurry the dried lignite with water and feed the gasifier. Because most of this water is "inherent" (nonsurface water contained in the coal structure) the lignite may reabsorb this water slowly enough to allow the resulting slurry to have a much higher carbon content than if as-received lignite was used. Dry feed gasifier systems are preferred when processing lignite. However, even then, the lignite must be dried to prevent blockage in the pressurized lock hoppers. Just how dry the lignite must be is uncertain but in this analysis it was assumed that 8 to12 weight percent moisture was necessary.

Hydrogen produced from Texas lignite in a coproduction plant could be produced in the range \$5.20-\$6.20/MMBTU (HHV basis) equivalent to between \$0.70 and \$0.84 per kilogram. The actual cost depends on the gasification system and the values of the co produced electric power and carbon dioxide. This range of hydrogen costs is equivalent to hydrogen produced by steam methane reforming of natural gas if the natural gas feed price was between \$3.00 and \$4.00/MMBTU. With natural gas prices continuing to remain above \$5.00/MMBTU this concept of using Texas lignite for hydrogen production would be economically viable.

For the production of SNG form Texas lignite, the costs range from \$6.90-\$5.00/MMBTU (HHV basis). This depends on the gasification system, the value of coproduced power, and the value of the carbon dioxide. If natural gas prices remain above \$5.00/MMBTU then the configuration using the advanced dry feed gasification system would be economically viable for production of SNG. This option may be even more attractive with other low rank coals such as Wyoming subbituminous and North Dakota lignite coals that are priced lower than Texas lignite.

Production of electric power from these conceptual coproduction plants provides a valuable revenue stream. Net power to sales averaged around 240 MW. It was assumed that these plants would be base load and that the value of the electricity was \$35.6/MWH.

The opportunity to sell carbon dioxide for EOR in Texas provided another valuable revenue stream for the plants. The break even cost of recovering the carbon dioxide ranged from about \$5.50 to \$7.75 per ton depending on whether SNG or hydrogen was the product. In this analysis it was assumed that the value of the carbon dioxide was \$12 per ton; therefore, at this value recovery was a profitable venture. With the worldwide movement towards regulation of carbon dioxide and greenhouse gases (GHG), these plants would qualify for future verifiable carbon dioxide emissions trading credits. The Chicago Climate Exchange (CCX) launched a GHG program in September 2003 and many companies signed up on a voluntary basis for trading. Carbon dioxide is trading for about \$1 per ton. In Europe on 1 January 2005, the European Union Emissions Trading Program begins. Therefore, plants that are already configured for carbon dioxide recovery will have an advantage in the future.

Please complete, make a copy to keep, and mail a copy to:

OPA

OCT 0 5 2006

BY 9

CHIEF CLERKS OFFICE

2006 OCT -5 AM 10:57

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Ms. LaDonna Castanuela, Chief Clerk
MC-105, TCEQ
P.O. Box 13087
Austin, Texas 78711-3087

Date Oct 4, 2006

105R / 49300

Re: Calhoun County Navigation District permit proposed for the former ES Joslin Power Plant site, Permit 45586 and PSD-TX-1055

I live or work or recreate approximately 2 miles (Lavaca/Matagorda Bay) [*e.g., NW or W*] from the old ES Joslin power plant near Point Comfort in Calhoun County, which is proposed to be converted from natural gas fuel to petroleum coke in the Calhoun County Navigation District permit 45586 and PSD-TX-1055.

☑ I am a member of the Sustainable Energy and Economic Development (SEED) Coalition.
☑ I am a member of Public Citizen.

I would be adversely affected by the pet coke fired power plant in the following ways [*Be as specific as possible. Would you worry about asthma or eye and nose irritation, or about fish you catch having mercury pollution from the plant, or would seeing or smelling the exhaust from the smokestack bother you;*

My name is Diane Wilson
I am president and founder of Calhoun County Resource Watch, a non profit group made up of Vietnamese, Hispanic and Anglo Commercial Shrimpers/fishermen who work in the Lavaca Bay/Matagorda Bay area. We will be adversely impacted by the emissions that will come from this proposed plant. Lavaca Bay is already home to a Mercury/Superfund site and (over)

Please add me to the mailing list for information related to this permit number and send me information about the hearing process.

Diane Wilson
Name

Box 1001
Address

Seadrift, Tx 77983
City, State, Zip Code

361-785-4680 or 361-676-0663
Daytime telephone

fax number

wilsonalamobay@aol.com
Email –Very important. Please print clearly – thanks.

(Call Karen Hadden, 512-797-8481 or Tom "Smitty" Smith, 512-477-1155 for more information.)

my son is autistic.
I am a fourth generation
fisherman/shrimper who has lived
in the Calhoun County area my entire
life. The lives of the Commercial
fishermen and their families will
be adversely affected by those
mercury emissions
and the lead, nitrogen oxide,
sulfur dioxide, particulates and hydrochloric
acid emissions

Sept 12, 2006

OPA

SEP 14 2006

BY ___

Dear Texas Commission on Environmental Quality,

I am concerned about air quality and the fast-tracking of coal plant permits in Texas.

I believe that new plants should meet or exceed the federal Clean Air Act standards, and these laws should be enforced - just like criminal laws.

Giving handouts to the large, profitable energy producing companies, at the expense of public health and the environment, is wrong.

I would expect a reputable agency such as yours to be able to stand up and do what's best for the citizens of Texas, and not be a puppet of powerful corporations and their politicians.

Texas is a technological leader, and should be using the best available technology and producing the nation's cleanest energy.

Attached is a list of permit names and numbers for which I am commenting.

Thanks for your consideration,

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

2006 SEP 14 AM 10: 23

CHIEF CLERKS OFFICE

Niles Seldon
8200 Neely Drive, Unit 138
Austin, TX 78759

BG

Proposed Coal Plant List

TXU Oak Grove Units 1 & 2
1720 MW
Franklin, Robertson County
TCEQ Permit No. 76474
EPA Permit No. PSD-TX-1056

49531

TXU Big Brown Unit 3
800 MW
Fairfield, Freestone County
TCEQ Permit No. 78759
EPA Permit No. PSD-TX-1065

53003

TXU Lake Creek Unit 3
800 MW
Riesel, McLennan County
TCEQ Permit No. 78751
EPA Permit No. PSD-TX-1070

53006

TXU Martin Lake Unit 4
800 MW
Tatum, Rusk County
TCEQ Permit No. 78750
EPA Permit No. PSD-TX-1071

53007

TXU Monticello Unit 4
800 MW
Mount Pleasant, Titus County
TCEQ Permit No. 78744
EPA Permit No. PSD-TX-1069

53008

TXU Morgan Creek Unit 7
800 MW
Colorado City, Mitchell County
TCEQ Permit No. 78761
EPA Permit No. PSD-TX-1066

52999

TXU Tradinghouse Units 3 & 4
1600 MW
Riesel, McLennan County
TCEQ Permit No. 78762
EPA Permit No. PSD-TX-1067

52993

TXU Valley Unit 4
800 MW
Bonham, Fannin County
TCEQ Permit No. 78763
EPA Permit No. PSD-TX-1068

53992

CPS San Antonio J,K. Spruce Unit 2
750 MW
San Antonio, Bexar County
TCEQ Permit No. 70492
EPA Permit No. PSD-TX-1037

31140 – closed

LS Power's Sandy Creek Unit 1
800 MW
Riesel, McLennan County
TCEQ Permit No. 70861
EPA Permit No. PSD-TX-1039

36558 – Closed

Nucoastal - Nu Coastal Energy Unit 1
300 MW
Point Comfort, Calhoun County
TCEQ Permit No. 45586
EPA Permit No. PSD-TX-1055

49300

Formosa Plastics
300 MW
Point Comfort, Calhoun County
TCEQ Permit No. 76044
EPA Permit No. PSD-TX-1053

48749

Sempra Twin Oaks Unit 3
600 MW
Bremond, Robertson County
TCEQ Permit No. 76381
EPA Permit No. PSD-TX-1054

49299

NRG Energy Limestone Unit 3
800 MW
Jewett, Limestone County
TCEQ Permit No. 79188
EPA Permit No. PSD-TX-1072

53550

CAPITOL OFFICE
P.O. BOX 12068
AUSTIN, TEXAS 78711-2068
(512) 463-0118
FAX: (512) 475-3736

SENATOR GLENN HEGAR

DISTRICT 18

DISTRICT OFFICE
P.O. BOX 1008
KATY, TEXAS 77492
(281) 391-8883
FAX: (281) 391-8818

TEXAS
COMMISSION
ON ENVIRONMENTAL
QUALITY

2007 APR 17 PM 2: 36

CHIEF CLERKS OFFICE

April 12, 2007

Mr. H.S. Buddy Garcia, Commissioner
Texas Commission of Environmental Quality
P.O. Box 13087
Austin, TX 78711-3087

2007-0168-AIR

Dear Mr. Garcia:

I am contacting your office regarding the matter of an air-born emissions permit for reactivation of the E S Joslin electric generating plant in Port Lavaca, to be considered before the commission on May 9, 2007.

Port Lavaca is one of the fastest growing areas of Texas and its beauty and economy are a tremendous asset to our great State. Port Lavaca has quickly become one of the most essential residential, as well as business areas, in Southern Texas. I truly believe the Texas Commission on Environmental Quality will take complete consideration of all related facts and arrive at a just and appropriate decision regarding the permit.

Thank you in advance for your consideration of the permit for the Port Lavaca project. I certainly appreciate you allowing me to share my views with you on this very important issue. If I may be assistance to you in the future, please do not hesitate to contact me.

Sincerely,

Glenn Hegar

GH /fm

RECEIVED

APR 16 2007

Texas Commission on Environmental Quality
Commissioners' Offices

FROM : Representative Burnam FAX NO. : 5127088454 May. 02 2007 02:47PM P1

STATE OF TEXAS
HOUSE OF REPRESENTATIVES

JUAN M. GARCIA III
STATE REPRESENTATIVE
DISTRICT 32

COMMITTEES
DEFENSE AFFAIRS AND
STATE-FEDERAL RELATIONS
AGRICULTURE AND LIVESTOCK

May 2, 2007

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
2007 MAY -3 AM 11:26
CHIEF CLERKS OFFICE

Chair Kathleen White
Texas Commission on Environmental Quality
P.O. Box 13087
Austin, Texas 78711-3087

Commissioner Larry R. Soward
Texas Commission on Environmental Quality
P.O. Box 13087
Austin, Texas 78711-3087

Commissioner H.S. Buddy Garcia
Texas Commission on Environmental Quality
P.O. Box 13087
Austin, Texas 78711-3087

Re: Docket No. 2007-0168-AIR; Application by Calhoun County Navigation District for Permits Nos. 45586 & PSD-TX-1055

Dear Chair and Commissioners:

I would like to express my support for the pending permit applications to repower and upgrade the existing E.S. Joslin Power Station near Point Comfort, Texas. I respectfully request that you deny the hearing requests that you will consider on the May 9, 2007 Commission Agenda.

My office has been following the development of this project and I support it completely. The Joslin Project represents a significant economic development project for my district. In addition to the temporary and permanent employment of local workers for the construction and operation of the Joslin Project, we hope that the Power Station and associated port facility improvements will help attract other industries and economic development projects to the area.

I understand that the Joslin Project incorporates state-of-the-art and commercially viable combustion technology to repower the power station with petroleum coke, which is a necessary byproduct of our robust petroleum refining industry along the Coastal Bend. After critical review by the Executive Director's staff and public comment, the pending permit application has been found to meet all state and federal regulatory requirements. The permit application protects public health and the environment.

The Joslin Project has been caught up in national and state-wide issues regarding coal-fired power plants. The issues raised in the hearing requests are not pertinent to the Joslin Project, which uses a different combustion technology and beneficially reuses petroleum coke as fuel, conserving other fossil-fuel resources. A contested-case hearing would serve no purpose other than to delay this necessary and worthwhile project.

We ask that you deny all hearing requests and issue the permit.

Sincerely,

Juan M. Garcia III

cc: Robert H. Van Borssum, PPM, Port Director
Calhoun Port Authority
fax (361) 987-2189