LARGE FILING SEPERATOR SHEET

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TESTIMONY CONTINUED

7. The Commission's designation of standardized high, medium and low per metric ton costs for atomospheric carbon emissions does not create a presumption of reasonableness for any of these standardized costs levels and does not preclude any utility or any participant from proposing any other cost per metric ton figure or any other alternative approach for dealing with such emissions in the IRP process.

I S S U E D at Santa Fe, New Mexico, this 16th day of May, 2007.

NEW MEXICO PUBLIC REGULATION COMMISSION

William J. Herrman

WILLIAM J. HERRMAN
Hearing Examiner

Carbon Dioxide Emission Allowance Prices
Assessment of U.S. Cap-and -Trade Proposals (April 2007)
M.I.T. Joint Program on the Science and Policy of Global Change
(2005$/Ton)

Scenario	2010	2015	2020	2025	2030	2035	2040	2045	2050
Reference Case									
Core Scenario - High	$0.00	$53.17	$64.69	$78.70	$95.76	$116.50	$141.74	$172.45	$209.81
Core Scenario - Mid	$0.00	$40.92	$49.79	$60.58	$73.70	$89.67	$109.10	$132.74	$161.49
Core Scenario - Low	$0.00	$17.72	$21.56	$26.23	$31.92	$38.83	$47.25	$57.48	$69.94
Developed countries only pursue mitigation - High	$0.00	$46.73	$56.85	$69.16	$84.15	$102.38	$124.56	$151.55	$184.38
Developed countries only pursue mitigation - Mid	$0.00	$26.10	$31.78	$38.64	$47.01	$57.19	$69.58	$84.66	$103.00
Developed countries only pursue mitigation - Low	$0.00	$12.41	$15.09	$18.36	$22.34	$27.18	$33.07	$40.24	$48.96
International emissions trading - High	$0.00	$0.02	$0.72	$22.87	$36.53	$109.74	$121.35	$140.77	$155.63
International emissions trading - Mid	$0.00	$0.02	$0.35	$19.39	$31.92	$100.91	$108.51	$123.61	$137.67
International emissions trading - Low	$0.00	$0.01	$0.13	$13.09	$23.09	$77.41	$84.74	$92.96	$101.69
Limited sectoral coverage - High	$0.00	$40.92	$49.79	$60.58	$73.70	$89.67	$109.10	$132.74	$161.49
Limited sectoral coverage - Mid	$0.00	$30.61	$37.25	$45.31	$55.13	$67.08	$81.61	$99.29	$120.80
Limited sectoral coverage - Low	$0.00	$13.70	$16.66	$20.27	$24.66	$30.01	$36.51	$44.42	$54.04
No banking - High	$0.00	$16.60	$47.98	$64.23	$76.60	$119.74	$237.26	$624.73	$2,559.38
No banking - Mid	$0.00	$10.05	$30.25	$53.25	$64.50	$107.92	$121.49	$139.59	$261.76
No banking - Low	$0.00	$6.28	$10.46	$12.09	$26.23	$53.10	$77.31	$92.69	$76.67
No biofuel trading - High	$0.00	$66.70	$81.16	$98.74	$120.13	$146.16	$177.82	$216.22	$263.22
No biofuel trading - Mid	$0.00	$49.30	$59.98	$72.98	$88.79	$108.03	$131.43	$159.91	$194.55
No biofuel trading - Low	$0.00	$17.66	$21.48	$26.14	$31.80	$38.69	$47.08	$52.27	$69.68
Nuclear expansion - High	$0.00	$13.70	$16.66	$20.27	$24.66	$30.01	$36.51	$44.42	$54.04
Nuclear expansion - Mid	$0.00	$40.60	$49.40	$60.10	$73.12	$88.97	$108.24	$131.69	$160.22
Nuclear expansion - Low	$0.00	$50.27	$61.16	$74.41	$90.53	$110.15	$134.01	$163.05	$198.37
Safety Valve: Safety valve price revised in 2030	$0.00	$7.02	$8.97	$11.44	$29.20	$37.26	$47.56	$60.69	$77.46
Safety Valve: US and rest of world pursue mitigation	$0.00	$7.02	$8.97	$11.44	$14.60	$18.64	$23.79	$30.36	$38.75
Safety Valve: US only pursues mitigation	$0.00	$7.02	$8.97	$11.44	$14.60	$18.64	$23.79	$30.36	$38.75
US only pursues mitigation - High	$0.00	$46.40	$56.46	$68.69	$83.57	$101.67	$123.70	$150.50	$183.11
US only pursues mitigation - Mid	$0.00	$20.30	$24.70	$30.05	$36.56	$44.48	$54.12	$65.85	$80.11
US only pursues mitigation - Low	$0.00	$9.99	$21.15	$14.79	$17.99	$21.89	$26.63	$32.40	$39.42
Quadratic Path: 50% below 1990 levels (230 bmt)	$0.00	$35.45	$43.13	$52.47	$63.84	$77.67	$94.50	$114.97	$139.88
Quadratic Path: 80% below 1990 levels (206 bmt)	$0.00	$41.89	$50.87	$62.01	$75.44	$91.79	$111.68	$135.87	$165.31

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RESEARCH

Increasing Construction Costs Could Hamper U.S. Utilities' Plans To Build New Power Generation

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As a result of declining reserve margins in some U.S. regions the U.S. brought about by a sustained growth of the economy, the domestic power industry is in the midst of an expansion. Standing in the way are capital costs of new generation that have risen substantially over the past three years. Cost pressures have been caused by demands of global infrastructure expansion. In the domestic power industry, cost pressures have arisen from higher demand for pollution control equipment, expansion of the transmission grid, and new generation.

While the industry has experienced buildout cycles in the past, what makes the current environment different is the supply-side resource challenges faced by the construction industry. A confluence of resource limitations have contributed, which Standard & Poor's Ratings Services broadly classifies under the following categories:

- Global demand for commodities,
- Material and equipment supply,
- Relative inexperience of new labor force, and
- Contractor availability.

The power industry has seen capital costs for new generation climb by more than 50% in the past three years, with more than 70% of this increase resulting from engineering, procurement, and construction (EPC) costs. Continuing demand, both domestic and international, for EPC services will likely keep costs at elevated levels. As a result, it is possible that with declining reserve margins, utilities could end up building generation at a time when labor and materials shortages cause capital costs to rise, well north of $2,500 per kW for supercritical coal plants and approaching $1,000 per kW for combined-cycle gas turbines (CCGT) (1). In a separate yet key point, as capital costs rise, energy efficiency and demand side management, already important from a climate change perspective, become even more crucial as any reduction in demand will mean lower requirement for new capacity.

Increasing capital costs will affect market participants to varying degrees. For regulated utilities, regulation remains the dominant credit driver. The key credit consideration for utilities with plants under development will be the preapproval of costs in rate base and timeliness of allowed returns as construction progresses. For utilities that choose to accept additional risks posed by nontraditional EPC contracts, agreements for recovery of potential cost increases or self-insurance against contingencies through reserve funds will also be important.

Construction risks of large projects undertaken by unregulated generation affiliates of diversified energy companies may affect the consolidated business risk profile, especially if costs aren't locked in and overages must be recovered from competitive market revenues. Project-financed, single-asset constructions that rely on nonstandard EPC contracts could be challenged to reach investment-grade ratings even if they are fully contracted post-construction.

The Resource Challenge

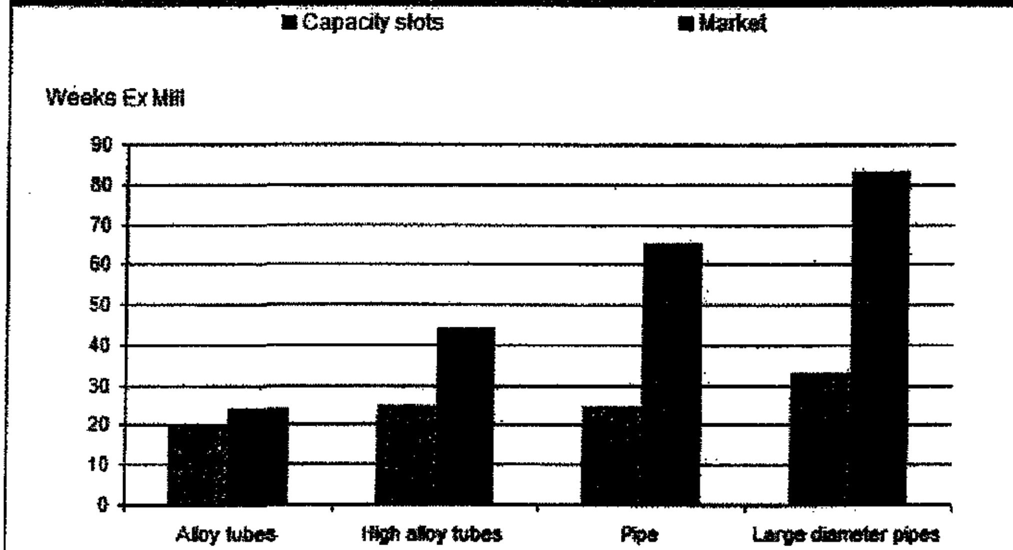
Global demand for commodities

A rapid increase in global demand, predominantly from Asia, has resulted in a sharp increase in prices for commodities important in the power sector. Some industry sources estimate that China's consumption accounted for about 40% of world cement supply and 25% of world steel supply in 2005 (2). A number of construction materials have seen a dramatic price increase in each of the years since the first quarter of 2004, and still remain at elevated levels. Prices of steel--up 50% in first half of 2004 alone--leveled off in 2005 but were on the rise again in 2007, up 20% over December 2005 (3). Copper products (up 60% since December 2005) and cement (up 15% since 2005) are the current drivers for continuing upward price pressures.

Material and equipment supply

In recent years, price competitiveness has encouraged (read: forced) original equipment manufacturers to employ global sourcing for raw material and fabrication needs. But here too the rapid growth in Asia, which is drawing on global supply for raw materials, is resulting in longer lead times and price increases. An example of this rapid growth is China: It went from an exporter of iron ore to being the world's largest importer by 2004 (4). Lead times for materials have increased (see chart) as raw material suppliers and fabrication facilities are taking reservation fees in order to secure availability of material and fabrication slots.

Tube And Pipe Leadtimes*



*As of March 2007. Source: Burns & Roe. Market implies no reservation.
© Standard & Poor's 2007.

Relative inexperience of new labor

While an extreme materials price escalation may have run its course, labor costs are becoming the new driver for industry inflation. The Construction Cost Index (CCI) (4) and the Building Cost Index (BCI) have increased at a compound annual growth rate of 5% and 5.5%, respectively, over the past three years. We learned in discussions with EPC contractors that the cost of labor has nearly doubled since the last round of construction in 2001. This labor cost and supply situation is due to a significant amount of construction experience that has retired and replaced by a new, less experienced work force resulting in reductions in labor productivity. And it could get worse: In the engineering sector, over 45% of labor will be eligible for retirement over the next five years. At the same time, strong global labor construction demand is leading to shortages of skilled labor, especially in the energy sector, which threatens the schedule and in-service dates of projects.

Contractor availability

Only a few contractors can absorb the risk of major construction projects. Sponsors are seeing more single bidder projects and an overall reduction in the number of bidders for projects.

Contract provisions are changing

The supply-side issues are causing a change in contract provisions offered by the construction industry. EPC contracts with guaranteed prices that shield utilities from cost overruns are now either very expensive, contain clauses that one can drive a truck through, or simply aren't offered. Simultaneously, we have seen the advent of risk-sharing mechanisms such as multi-prime contracting (EPCM), which distributes construction risk between contractor and sponsor but lowers installed cost.

To be clear though, the record of construction over the past few years when contractors got hit with performance penalties is another reason that contract provisions have changed. Still, the supply issues have allowed contractors the upper hand. We have increasingly seen the use of adjustment clauses as contractors respond to material price escalations, including:

- Material escalation clauses that track the actual variation of prices from bid amounts,
- The use of indices to adjust prices, commonly CCI (which assigns a higher weighting to labor costs) and also the Materials Cost Index,
- An escalation allowance line item in contracts that serves as a cap for the contractor to recover unanticipated cost increases,
- The use of surcharges typically to limit fuel-only escalations, and
- The re-emergence of cost-based plus contracting.

Extent Of Cost Increase

We assessed the magnitude of cost increases by comparing coal projects under construction during 2003 to 2006. Table 1 lists some coal-fired generation projects currently under development:

Table 1

Coal Plants Under Construction

Power plant	Location	Primary owner	Size (MW)	Type of unit	EPC contract	Year EPC contracted	Broke ground	Expected completion	Project cost ($ per kW)
Council Bluffs Unit 4	Iowa	MidAmerican Energy Co.	790	Super-critical	Fixed	2002	2003	2007	1,848
Elm Road	Wisconsin	Wisconsin Energy Corp.	1,230	Super-critical	Fixed	2002/2003	2004	2009/2010	1,781
Weston 4	Wisconsin	WPS Resources Corp.	500	Super-critical	Multi-prime	2002/2003	2004	2008	1,650
Nebraska City 2	Nebraska	Omaha Public Power District	653	Sub critical	Fixed	2004	2005	2009	1,600
Iatan Unit 2	Missouri	Kansas City Power & Light Co.	850	Super-critical	Multi-prime	December 2005	2006	2010	1,985
Plum Point	Arkansas	Plum Point Energy Associates	663	Sub-critical	Fixed	2005	2006	2010	2,150
LongView	Pennsylvania	LongView Power LLC	695	Super-critical	Multi	2006	2007	2010	2,600

Sub and supercritical technologies result in minor differences to capital cost. Adjustments were made to AFUDC/funded interest to make the comparison relevant. Some projects also have modest other costs such as coal cars or transmission connects. AFUDC--Allowance for funds used during construction. EPC--Engineering, procurement, and construction.

The sample is small but the trend is evident. Broadly, capital costs have risen, from about $1,700 per kW in 2003-2004 to about $2,500 per kW by year-end 2006. The increase was sharp from 2005 to 2006. A key comparison is between Nebraska City #2 (NC#2) and the Plum Point Project as these two allow us to control all other cost variables--they are of similar size and have a fixed priced EPC that is contracted with the same construction consortium (we recognize that the existing site gives NC#2 some advantages). The important distinction is that the construction contracting was a year apart. Capital costs for Plum Point were almost 35% higher. The fixed price EPC component for Plum Point was almost 40% higher, increasing to nearly $1,325 per kW compared with $960 per kW for NC#2. For the Longview project, which completed construction contract negotiations a year after Plum Point, the EPC contract price is a further 30% higher at about $1,700 per kW.

New combined-cycle plants have similar issues

We had informal discussions with some EPC contractors to determine the effect on new combined-cycle plants (see table 2). The theme is similar. Labor costs have nearly doubled since the last construction cycle, from about 25% to nearly 40% of total project cost. Other factors included higher costs of commodities like copper, steel, and cement, somewhat offset by reductions in turbine costs. The range of about $745 to $785 per kW is about 20% to 25% higher than costs in 2002. The high range is about 60% higher than price in 2002.

Table 2

Combined-Cycle Plant Cost Comparison*

($ per kW)	EPC 1	EPC 2 low range	EPC 3	Average	EPC 1 high range	EPC 2 High Range
EPC cost	630	615	650	632	870	760
Soft cost¶	160	125	195	160	220	225
Total	790	740	845	792	1090	985

*Costs estimated by three different EPC contractors. Estimates are identified as EPC 1, EPC 2, and EPC 3. ¶Soft costs include water supply, finance, legal, IDC, and natural gas pipe connects. EPC--Engineering, procurement, and construction.

Still, these units have shorter construction lead times and can be carried on utilities' balance sheets without significant credit impact. Together with potential future costs relating to climate change, we could see the cancellation of some coal-fired construction projects and a shift in favor of natural gas fired units. However, supply, longer-term prices, and volatility of natural gas will remain concerns.

Credit Implications For Industry Participants

Because the electric industry is entering a period of sustained building after a prolonged absence, companies are again highly dependent on regulatory decisions for full recovery of these growing costs. There has also been a shift in this round of heavy construction to predominantly rate-based recovery as regulated utilities undertake many large projects. However, regulators are dealing with cost pressures from a variety of other factors, such as expiring frozen/capped periods, fuel cost recovery, distribution related base rate requests, and extensive spending related to environmental emissions control. After the relatively calm period of transition/rate freeze agreements between 1996 and 2005, the sheer volume of rate cases facing regulators will pose a challenge. Balancing competing priorities of maintaining reliability and avoiding rate shocks will be an unenviable job, and some rate-case orders may result in regulatory deferrals or even pressure the full recoverability of rate-based plants, which could weaken some utilities' credit quality.

Recognizing the need for new power, some states are enacting laws that allow utilities to seek regulatory decisions that effectively preapprove the costs of new generation facilities. Rulemaking clarity is also being provided by specifying the rate-making principles that commissions will apply when that new generation can be placed in the utility's rate base. House Bill 577 in Iowa, Senate Bill 79 in Wisconsin, Senate Bill 1416 in Virginia, and House Bill 1910 in Oklahoma are examples of such efforts. While the laws in Wisconsin, Oklahoma, and Virginia remain untested, MidAmerican Energy Co. used Iowa's HF 577 to seek preapproval of its 60.67% ownership interest in the Council Bluffs facility. Pursuant to rate settlements in Iowa, MidAmerican Energy will be permitted to include in its rate base the Iowa portion of up to $682.5 million in construction costs and earn a 12.29% return on equity once the 790 MW plant is completed. Costs exceeding this cap would be recoverable if determined to have been prudently incurred.

Credit implications for regulated utilities should be fairly straight forward. As long as the utility in the process of building a large project has access to protective safeguards like regulatory preapproval for construction, timely recovery on capital work in progress, and other cost-recovery mechanisms, it can meaningfully mitigate the large risks posed by construction projects. Still, these utilities will have to manage overall risks during the construction process to avoid cost overruns. For example, despite their approved fixed-price EPC construction for the Elm Road project, Wisconsin Energy Corp. and Madison Gas & Electric Co. will have to absorb cost escalations from more stringent environmental requirements if overall cost overruns exceed 5% of the approved capital cost.

Regulated utilities that forego the protection of a fixed EPC will increase their exposure to construction risk from material cost increases, scheduling delays, and performance issues. In such cases, we look for regulatory pre-agreements that lessen the risk of disallowance or restricted reserves that mitigate the risk of overruns. Some utilities also address risk by partaking in large projects through joint ownership interest. Utilities have also used a combination of these strategies. The Iaton 2 project is a good example of a EPCM approach that is structured to protect its owners' credit quality. The project has five owners, but two owners, Kansas City Power & Light Co. and Empire District Electric Co., are allowed to accelerate plant-related amortization expense in rate proceedings occurring before the in-service date, and the project has nearly 12.5% of project costs in contingency reserves.

Unregulated generation companies can't recover any of their capital investment through regulated means and must rely on market prices to recover these investments. The current environment of increasing prices has pressured the economics of merchant generation. While capacity markets can provide visibility into market-based revenues in some areas, they have not developed enough to provide the certainty needed to support generation projects with long lead times. However, the capacity clearing price of PJM's first reliability pricing model auction for the eastern Mid-Atlantic Area Council subregion is close to the price that can support new CCGT capital costs. However, it's too early to tell whether this will drive significant unregulated construction activity. We do expect some unregulated generation affiliates of diversified utilities to consider self-build options for CCGTs to lower installed cost. Implications for credit quality will depend on the relative magnitude of construction risk and the presence of mitigating factors like contingency reserves.

Regions with strong demand and depleting reserve margins will see some project finance-based debt issuances. The 695 MW Longview project is a good example of a recently rated merchant project finance transaction. However, in that case, merchant risks dominated the credit–quality considerations. Plum Point is an example of a fully contracted coal-fired plant with a fixed-price EPC currently under construction. The project has investment-grade characteristics supported by 16.5% of the EPC contract price in contingency reserve and contingent equity during construction.

Notes

(1) We exclude nuclear from this discussion as investments in nuclear units may only be in the medium to long term, and potentially at over $4,000 per kW.

(2) John Gallagher and Frank Briggs, Construction Briefings, December 2006, Thomas West.

(3) U.S. Bureau of Labor Statistics.

(4) The Financial Times, Jan. 27, 2004.

(5) Engineering News-Record, a unit of McGraw-Hill Companies. Both the CCI and BCI indexes have labor as the major component at 80% and 64%, respectively.

Other Sources

- "Construction Contract Provisions: Credit Considerations For Utilities That Are Building Owned Generation" published on RatingsDirect on March 30, 2005.
- "Regulatory Support Is Key For U.S. Utilities Building New Coal-Fired Power Plants" published on RatingsDirect on Nov. 3, 2006.

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Rising Utility Construction Costs:

Sources and Impacts

Prepared by:

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The Brattle Group

Prepared for:

The EDISON FOUNDATION

SEPTEMBER 2007

The Edison Foundation is a nonprofit organization dedicated to bringing the benefits of electricity to families, businesses, and industries worldwide.

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Table of Contents

Introduction and Executive Summary

In *Why Are Electricity Prices Increasing? An Industry-Wide Perspective* (June 2006), *The Brattle Group* identified fuel and purchased-power cost increases as the primary driver of the electricity rate increases that consumers currently are facing. That report also noted that utilities are once again entering an infrastructure expansion phase, with significant investments in new baseload generating capacity, expansion of the bulk transmission system, distribution system enhancements, and new environmental controls. The report concluded that the industry could make the needed investments cost-effectively under a generally supportive rate environment.

The rate increase pressures arising from elevated fuel and purchased power prices continue. However, another major cost driver that was not explored in the previous work also will impact electric rates, namely, the substantial increases in the costs of building utility infrastructure projects. Some of the factors underlying these construction cost trends are straightforward—such as sharp increases in materials cost—while others are complex, and sometimes less transparent in their impact. Moreover, the recent rise in many utility construction cost components follows roughly a decade of relatively stable (or even declining) real construction costs, adding to the "sticker shock" that utilities experience when obtaining cost estimates or bids and that state public utility commissions experience during the process of reviewing applications for approvals to proceed with construction. While the full rate impact associated with construction cost increases will not be seen by customers until infrastructure projects are completed, the issue of rising construction costs currently affects industry investment plans and presents new challenges to regulators.

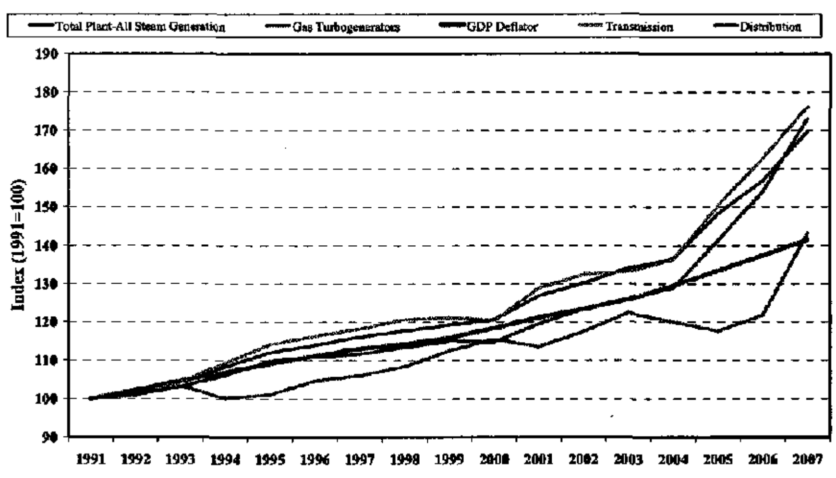
The purpose of this study is to a) document recent increases in the construction cost of utility infrastructure (generation, transmission, and distribution), b) identify the underlying causes of these increases, and c) explain how these increased costs will translate into higher rates that consumers might face as a result of required infrastructure investment. This report also provides a reference for utilities, regulators and the public to understand the issues related to recent construction cost increases. In summary, we find the following:

- Dramatically increased raw materials prices (*e.g.,* steel, cement) have increased construction cost directly and indirectly through the higher cost of manufactured components common in utility infrastructure projects. These cost increases have primarily been due to high global demand for commodities and manufactured goods, higher production and transportation costs (in part owing to high fuel prices), and a weakening U.S. dollar.
- Increased labor costs are a smaller contributor to increased utility construction costs, although that contribution may rise in the future as large construction projects across the country raise the demand for specialized and skilled labor over current or projected supply. There also is a growing backlog of

project contracts at large engineering, procurement and construction (EPC) firms, and construction management bids have begun to rise as a result. Although it is not possible to quantify the impact on future project bids by EPC firms, it is reasonable to assume that bids will become less cost-competitive as new construction projects are added to the queue.

- The price increases experienced over the past several years have affected all electric sector investment costs. In the generation sector, all technologies have experienced substantial cost increases in the past three years, from coal plants to windpower projects. Large proposed transmission projects have undergone cost revisions, and distribution system equipment costs have been rising rapidly. This is seen in Figure ES-1, which shows recent price trends in generation, transmission and distribution infrastructure costs based on the Handy-Whitman Index© data series, compared with the general price level as measured by the gross domestic product (GDP) deflator over the same time period.[1] As shown in Figure ES-1, infrastructure costs were relatively stable during the 1990s, but have experienced substantial price increases in the past several years. Between January 2004 and January 2007, the costs of steam-generation plant, transmission projects and distribution equipment rose by 25 percent to 35 percent (compared to an 8 percent increase in the GDP deflator). For example, the cost of gas turbines, which was fairly steady in the early part of the decade, increased by 17 percent during the year 2006 alone. As a result of these cost increases, the levelized capital cost component of baseload coal and nuclear plants has risen by $20/MWh or more—substantially narrowing coal's overall cost advantages over natural gas-fired combined-cycle plants—and thus limiting some of the cost-reduction benefits expected from expanding the solid-fuel fleet.

Figure ES-1
National Average Utility Infrastructure Cost Indices

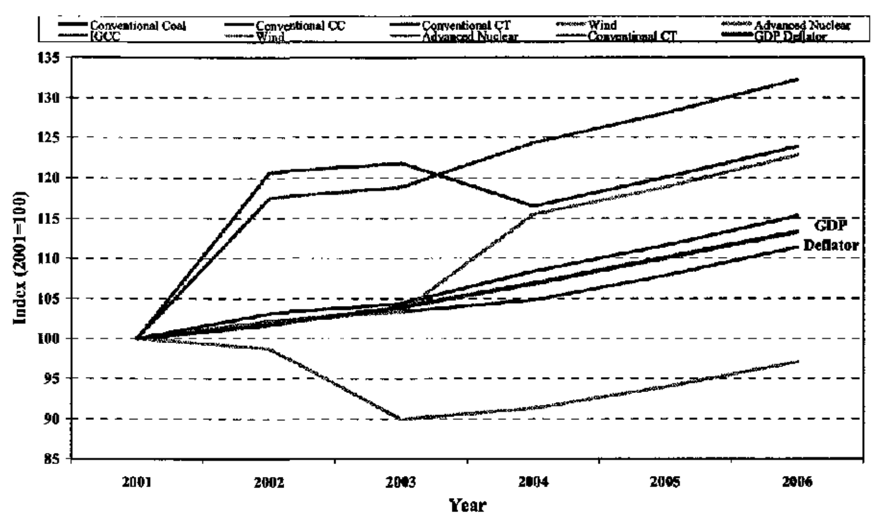


Sources: The Handy-Whitman© Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indexes for the specified components.

[1] The GDP deflator measures the cost of goods and services purchased by households, industry and government, and as such is a broader price index than the Consumer Price Index (CPI) or Producer Price Index (PPI), which track the costs of goods and services purchased by households and industry, respectively.

- The rapid increases experienced in utility construction costs have raised the price of recently completed infrastructure projects, but the impact has been mitigated somewhat to the extent that construction or materials acquisition preceded the most recent price increases. The impact of rising costs has a more dramatic impact on the estimated cost of proposed utility infrastructure projects, which fully incorporates recent price trends. This has raised significant concerns that the next wave of utility investments may be imperiled by the high cost environment. These rising construction costs have also motivated utilities and regulators to more actively pursue energy efficiency and demand response initiatives in order to reduce the future rate impacts on consumers.
- Despite the overwhelming evidence that construction costs have risen and will be elevated for some time, these increased costs are largely absent from the capital costs specified in the Energy Information Administration's (EIA's) 2007 *Annual Energy Outlook* (AEO). The AEO generation capital cost assumptions since 2001 are shown in Figure ES-2. Since 2004, capital costs of all technologies are assumed to grow at the general price level—a pattern that contradicts the market evidence presented in this report. The growing divergence between the AEO data assumptions and recent cost escalation is now so substantial that the AEO data need to be adjusted to reflect recent cost increases to provide reliable indicators of current or future capital costs.

Figure ES-2
EIA Generation Construction Cost Estimates



Sources: Data collected from the U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2002 to 2007* and from the U.S. Bureau of Economic Analysis.

Projected Investment Needs and Recent Infrastructure Cost Increases

Current and Projected U.S. Investment in Electricity Infrastructure

The electric power industry is a very capital-intensive industry. The total value of generation, transmission and distribution infrastructure for regulated electric utilities is roughly $440 billion (property in service, net of accumulated depreciation and amortization), and capital expenditures are expected to exceed $70 billion in 2007.[2] Although the industry as a whole is always investing in capital, the rate of capital expenditures was relatively stable during the 1990s and began to rise near the turn of the century. As shown in *Why Are Electricity Prices Increasing? An Industry-Wide Perspective* (June 2006), utilities anticipate substantial increases in generation, transmission and distribution investment levels over the next two decades. Moreover, the significant need for new electricity infrastructure is a world-wide phenomenon: According to the *World Energy Investment Outlook 2006*, investments by power-sector companies throughout the world will total about $11 trillion dollars by 2030.[3]

Generation

As of December 31, 2005, there were 988 gigawatts (GW) of electric generating capacity in service in the U.S., with the majority of this capacity owned by electric utilities. Close to 400 GW of this total, or 39 percent, consists of natural gas-fired capacity, with coal-based capacity comprising 32 percent, or slightly more than 300 GW, of the U.S. electric generation fleet. Nuclear and hydroelectric plants comprise approximately 10 percent of the electric generation fleet. Approximately 49 percent of energy production is provided by coal plants, with 19 percent provided by nuclear plants. Natural gas-fired plants, which tend to operate as intermediate or peaking plants, also provided about 19 percent of U.S. energy production in 2006.

The need for installed generating capacity is highly correlated with load growth and projected growth in peak demand. According to EIA's most recent projections, U.S. electricity sales are expected to grow at an annual rate of about 1.4 percent through 2030. According to the North American Electric Reliability Corporation (NERC), U.S. non-coincident peak demand is expected to grow by 19 percent (141 GW) from 2006 to 2015. According to EIA, utilities will need to build 258 GW of new generating capacity by 2030 to meet the

[2] Net property in service figure as of December 31, 2006, derived from Federal Energy Regulatory Commission (FERC) Form 1 data compiled by the Edison Electric Institute (EEI). Gross property is roughly $730 billion, with about $290 billion already depreciated and/or amortized. Annual capital expenditure estimate is derived from a sample of 10K reports surveyed by EEI.

[3] Richard Stavros. "Power Plant Development: Raising the Stakes." *Public Utilities Fortnightly*, May 2007, pp. 36-42.

projected growth in electricity demand and to replace old, inefficient plants that will be retired. EIA further projects that coal-based capacity, that is more capital intensive than natural gas-fired capacity which dominated new capacity additions over the last 15 years, will account for about 54 percent of total capacity additions from 2006 to 2030. Natural gas-fired plants comprise 36 percent of the projected capacity additions in *AEO 2007*. EIA projects that the remaining 10 percent of capacity additions will be provided by renewable generators (6 percent) and nuclear power plants (4 percent). Renewable generators and nuclear power plants, similar to coal-based plants, are capital-intensive technologies with relatively high construction costs but low operating costs.

High-Voltage Transmission

The U.S. and Canadian electric transmission grid includes more than 200,000 miles of high voltage (230 kV and higher) transmission lines that ultimately serve more than 300 million customers. This system was built over the past 100 years, primarily by vertically integrated utilities that generated and transmitted electricity locally for the benefit of their native load customers. Today, 134 control areas or balancing authorities manage electricity operations for local areas and coordinate reliability through the eight regional reliability councils of NERC.

After a long period of decline, transmission investment began a significant upward trend starting in the year 2000. Since the beginning of 2000, the industry has invested more than $37.8 billion in the nation's transmission system. In 2006 alone, investor-owned electric utilities and stand-alone transmission companies invested an historic $6.9 billion in the nation's grid, while the Edison Electric Institute (EEI) estimates that utility transmission investments will increase to $8.0 billion during 2007. A recent EEI survey shows that its members plan to invest $31.5 billion in the transmission system from 2006 to 2009, a nearly 60-percent increase over the amount invested from 2002 to 2005. These increased investments in transmission are prompted in part by the larger scale of base load generation additions that will occur farther from load centers, creating a need for larger and more costly transmission projects than those built over the past 20 years. In addition, new government policies and industry structures will contribute to greater transmission investment. In many parts of the country, transmission planning has been formally regionalized, and power markets create greater price transparency that highlights the value of transmission expansion in some instances.

NERC projects that 12,873 miles of new transmission will be added by 2015, an increase of 6.1 percent in the total miles of installed extra high-voltage (EHV) transmission lines (230 kV and above) in North America over the 2006 to 2015 period. NERC notes that this expansion lags demand growth and expansion of generating resources in most areas. However, NERC's figures do not include several major new transmission projects proposed in the PJM Interconnection LLC, such as the major new lines proposed by American Electric Power, Allegheny Power, and Pepco.

Distribution

While transmission systems move bulk power across wide areas, distribution systems deliver lower-voltage power to retail customers. The distribution system includes poles, as well as metering, billing, and other related infrastructure and software associated with retail sales and customer care functions. Continual investment in distribution facilities is needed, first and foremost, to keep pace with growth in customer demand. In real terms, investment began to increase in the mid-1990s, preceding the corresponding boom in generation. This steady climb in investment in distribution assets shows no sign of diminishing. The need to replace an aging infrastructure, coupled with increased population growth and demand for power quality and customer service, is continuing to motivate utilities to improve their ultimate delivery system to customers.

Continued customer load growth will require continued expansion in distribution system capacity. In 2006, utilities invested about $17.3 billion in upgrading and expanding distribution systems, a 32-percent increase over the investment levels incurred in 2004. EEI projects that distribution investment during 2007 will again exceed $17.0 billion. While much of the recent increase in distribution investment reflects expanding physical infrastructure, a substantial portion of the increased dollar investment reflects the increased input costs of materials and labor to meet current distribution infrastructure needs.

Construction Costs for Recently Completed Generation

The majority of recently constructed plants have been either natural gas-fired or wind power plants. Both have displayed increasing real costs for several years. Since the 1990s, most of the new generating capacity built in the U.S. has been natural gas-fired capacity, either natural gas-fired combined-cycle units or natural gas-fired combustion turbines. Combustion turbine prices recently rose sharply after years of real price decreases, while significant increases in the cost of installed natural gas combined-cycle combustion capacity have emerged during the past several years.

Using commercially available databases and other sources, such as financial reports, press releases and government documents, *The Brattle Group* collected data on the installation cost of natural gas-fired combined-cycle generating plants built in the U.S. during the last major construction cycle, defined as generating plants brought into service between 2000 and 2006. We estimated that the average real construction cost of all natural gas-fired combined-cycle units brought online between 2000 and 2006 was approximately $550/kilowatt (kW) (in 2006 dollars), with a range of costs between $400/kW to approximately $1,000/kW. Statistical analysis confirmed that real installation cost was influenced by plant size, the turbine technology, the NERC region in which the plant was located, and the commercial online date. Notably, we found a positive and statistically significant relationship between a plant's construction cost and its online date, meaning that, everything else equal, the later a plant was brought online; the higher its real installation cost.[4] Figure 1 shows the average yearly installation cost, in *nominal* dollars, as predicted by the regression analysis.[5] This figure shows that the average installation cost of combined-cycle units increased gradually from 2000 to 2003, followed by a fairly significant increase in 2004 and a very significant escalation—more than $300/kW—in 2006. This provides vivid evidence of the recent sharp increase in plant construction costs.

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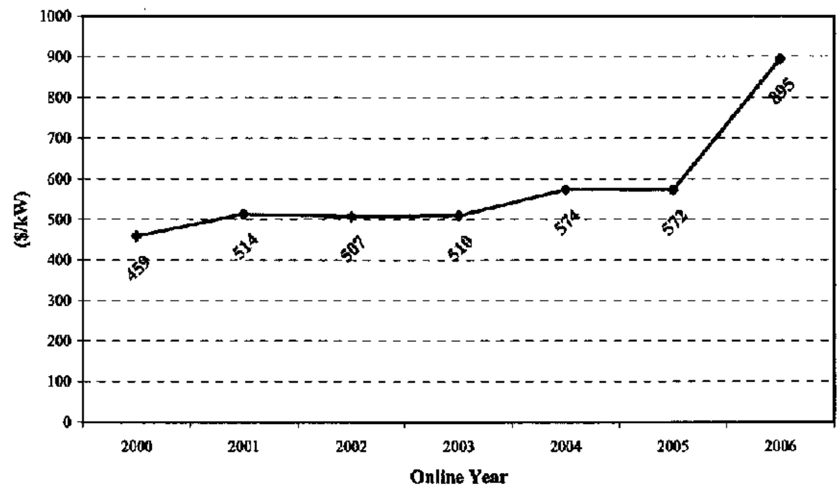
[4] To be precise, we used a "dummy" variable to represent each year in the analysis. The year-specific dummy variables were statistically significant and uniformly positive; *i.e.*, they had an upward impact on installation cost.

[5] The nominal form regression results are discussed here to facilitate comparison with the GDP deflator measure used to compare other price trends in other figures in this report.

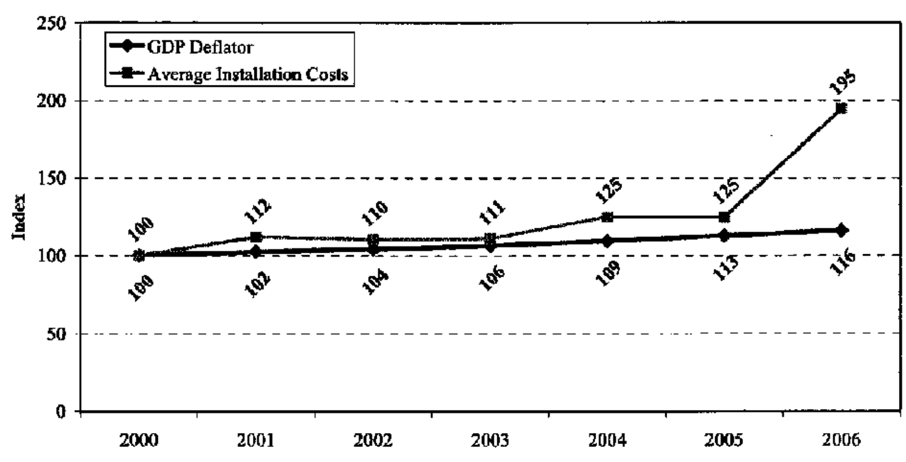
Figure 1
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year ($/kW)



Sources and Notes:
* Data on summer capacity, total installation cost, turbine technology, commercial online date, and zip code for the period 2000-2006 were collected from commercially available databases and other sources such as company websites and 10k reports.

Figure 2 compares the trend in plant installation costs to the GDP deflator, using 2000 as the base year. Over the period of 2000 to 2006, the cumulative increase in the general price level was 16 percent while the cumulative increase in the installation cost of new combined-cycle units was almost 95 percent, with much of this increase occurring in 2006.

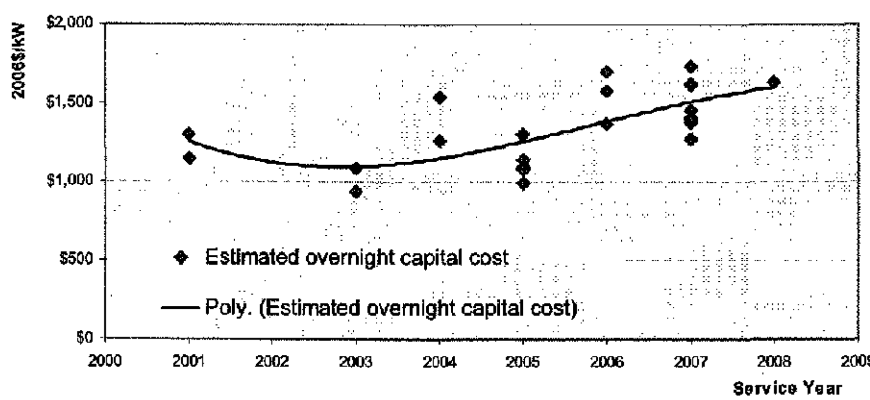
Figure 2
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year (Index Year 2000 = 100)



Sources and Notes:
* Data on summer capacity, total installation cost, turbine technology, commercial online date, and zip code for the period 2000-2006 were collected from commercially available databases and other sources such as company websites and 10k reports.
** GDP Deflator data were collected from the U.S. Bureau of Economic Analysis.

Another major class of generation development during this decade has been wind generation, the costs of which have also increased in recent years. The Northwest Power and Conservation Council (NPCC), a regional planning council that prepares long-term electric resource plans for the Pacific Northwest, issued its most recent review of the cost of wind power in July 2006.[6] The Council found that the cost of new wind projects rose substantially in real terms in the last two years, and was much higher than that assumed in its most recent resource plan. Specifically, the Council found that the levelized lifecycle cost of power for new wind projects rose 50 to 70 percent, with higher construction costs being the principal contributor to this increased cost. According to the Council, the construction cost of wind projects, in real dollars, has increased from about $1150/kW to $1300-$1700/kW in the past few years, with an unweighted average capital cost of wind projects in 2006 at $1,485/kW. Factors contributing to the increase in wind power costs include a weakening dollar, escalation of commodity and energy costs, and increased demand for wind power under renewable portfolio standards established by a growing number of states. The Council notes that commodities used in the manufacture and installation of wind turbines and ancillary equipment, including cement, copper, steel and resin have experienced significant cost increases in recent years. Figure 3 shows real construction costs of wind projects by actual or projected in-service date.

Figure 3
Wind Power Project Capital Costs



Source: The Northwest Power and Conservation Council, "Biennial Review of the Cost of Windpower" July 13, 2006.

These observations were confirmed recently in a May 2007 report by the U.S. Department of Energy (DOE), which found that prices for wind turbines (the primary cost component of installed wind capacity) rose by more than $400/kW between 2002 and 2006, a nearly 60-percent increase.[7] Figure 4 is reproduced from the DOE report (Figure 21) and shows the significant upward trend in turbine prices since 2001.

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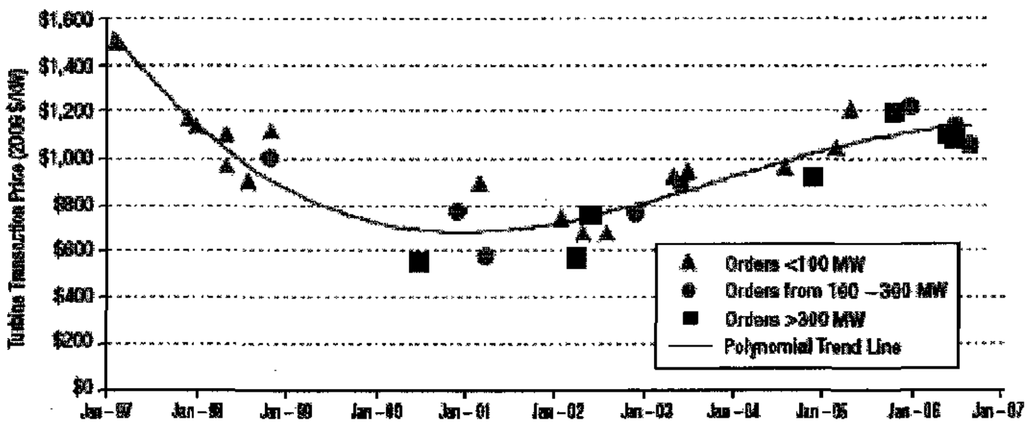
[6] The NPCC planning studies and analyses cover the following four states: Washington, Oregon, Idaho, and Montana. See "Biennial Review of the Cost of Windpower" July 13, 2006, at www.bpa.gov/Energy/N/projects/post2006conservation/doc/Windpower_Cost_Review.doc. This study provides many reasons for windpower cost increases.

[7] See U.S. Department of Energy, *Annual Report on U.S. Wind Power Installation, Cost and Performance Trends: 2006* Figure 21, page 16.

Figure 4
Wind Turbine Prices 1997 - 2007



Source: Berkeley Lab database.

Rising Projected Construction Costs: Examples and Case Studies

Although recently completed gas-fired and wind-powered capacity has shown steady real cost increases in recent years, the most dramatic cost escalation figures arise from *proposed* utility investments, which fully reflect the recent, sharply rising prices of various components of construction and installation costs. The most visible of these are generation proposals, although several transmission proposals also have undergone substantial upward cost revisions. Distribution-level investments are smaller and less discrete ("lumpy") and thus are not subject to similar ongoing public scrutiny on a project-by-project basis.

Coal-Based Power Plants

Evidence of the significant increase in the construction cost of coal-based power plants can be found in recent applications filed by utilities, such as Duke Energy and Otter Tail Power Company, seeking regulatory approval to build such plants. Otter Tail Power Company leads a consortium of seven Midwestern utilities that are seeking to build a 630-MW coal-based generating unit (Big Stone II) on the site of the existing Big Stone Plant near Milbank, South Dakota. In addition, the developers of Big Stone II seek to build a new high-voltage transmission line to deliver power from Big Stone II and from other sources, including possibly wind and other renewable forms of energy. Initial cost estimates for the power plant were about $1 billion, with an additional $200 million for the transmission line project. However, these cost estimates increased dramatically, largely due to higher costs for construction materials and labor.[8] Based on the most recent design refinements, the project, including transmission, is expected to cost $1.6 billion.

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[8] Other factors contributing to the cost increase include design changes made by project participants to increase output and improve the unit's efficiency. For example, the voltage of the proposed transmission line was increased from 230 kV to 345 kV to accommodate more generation.

In June 2006, Duke submitted a filing with the North Carolina Utilities Commission (NCUC) seeking a certificate of public convenience and necessity for the construction of two 800 MW coal-based generating units at the site of the existing Cliffside Steam Station. In its initial application, Duke relied on a May 2005 preliminary cost estimate showing that the two units would cost approximately $2 billion to build. Five months later, Duke submitted a second filing with a significantly revised cost estimate. In its second filing, Duke estimated that the two units would cost approximately $3 billion to build, a 50 percent cost increase. The North Carolina Utilities Commission approved the construction of one 800 MW unit at Cliffside but disapproved the other unit, primarily on the basis that Duke had not made a showing that it needed the capacity to serve projected native load demands. Duke's latest projected cost for building one 800 MW unit at Cliffside is approximately $1.8 billion, or about $2,250/kW. When financing costs, or allowance for funds used during construction (AFUDC), are included, the total cost is estimated to be $2.4 billion (or about $3,000/kW).

Rising construction costs have also led utilities to reconsider expansion plans prior to regulatory actions. In December 2006, Westar Energy announced that it was deferring the consideration of a new 600 MW coal-based generation facility due to significant increases in the estimated construction costs, which increased from $1.0 billion to about $1.4 billion since the plant was first announced in May 2005.

Increased construction costs are also affecting proposed demonstration projects. For example, DOE announced earlier this year that the projected cost for one of its most prominent clean coal demonstration project, FutureGen, had nearly doubled.[9] FutureGen is a clean coal demonstration project being pursued by a public-private partnership involving DOE and an alliance of industrial coal producers and electric utilities. FutureGen is an experimental advanced Integrated Gasification Combined Cycle (IGCC) coal plant project that will aim for near zero emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), mercury, particulates and carbon dioxide (CO_2). Its initial cost was estimated at $950 million. But after re-evaluating the price of construction materials and labor and adjusting for inflation over time, DOE's Office of Fossil Energy announced that the project's price had increased to $1.7 billion.

Transmission Projects

NSTAR, the electric distribution company that serves the Boston metropolitan area, recently built two 345 kV lines from a switching station in Stoughton, Massachusetts, to substations in the Hyde Park section of Boston and to South Boston, respectively. In an August 2004 filing before ISO New England Inc. (ISO-NE), NSTAR indicated that the project would cost $234.2 million. In March 2007, NSTAR informed ISO-NE that estimated project costs had increased by $57.7 million, or almost 25 percent, for a revised total project cost of $292 million. NSTAR stated that the increase is driven by increases in both construction and material costs, with construction bids coming in 24 percent higher than initially estimated. NSTAR further explained that there have been dramatic increases in material costs, with copper costs increasing by 160 percent, core steel by 70 percent, flow-fill concrete by 45 percent, and dielectric fluid (used for cable cooling) by 66 percent.

[9] U.S. Department of Energy, April 10, 2007, press release available at http://www.fossil.energy.gov/news/techlines/2007/07019-DOE_Signs_FutureGen_Agreement.html

Another aspect of transmission projects is land requirements, and in many areas of the country land prices have increased substantially in the past few years. In March 2007, the California Public Utilities Commission (CPUC) approved construction of the Southern California Edison (SCE) Company's proposed 25.6-mile, 500 kV transmission line between SCE's existing Antelope and Pardee Substations. SCE initially estimated a cost of $80.3 million for the Antelope-Pardee 500 kV line. However, the company subsequently revised its estimate by updating the anticipated cost of acquiring a right-of-way, reflecting a rise in California's real estate prices. The increased land acquisition costs increased the total estimate for the project to $92.5 million, increasing the estimated costs to more than $3.5 million per mile.

Distribution Equipment

Although most individual distribution projects are small relative to the more visible and public generation and transmission projects, costs have been rising in this sector as well. This is most readily seen in Handy-Whitman Index© price series relating to distribution equipment and components. Several important categories of distribution equipment have experienced sharp price increases over the past three years. For example, the prices of line transformers and pad transformers have increased by 68 percent and 79 percent, respectively, between January 2004 and January 2007, with increases during 2006 alone of 28 percent and 23 percent.[10] The cost of overhead conductors and devices increased over the past three years by 34 percent, and the cost of station equipment rose by 38 percent. These are in contrast to the overall price increases (measured by the GDP deflator) of roughly 8 percent over the past three years.

[10] Handy-Whitman© Bulletin No. 165, average increase of six U.S. regions. Used with permission.

Factors Spurring Rising Construction Costs

Broadly speaking, there are four primary sources of the increase in construction costs: (1) material input costs, including the cost of raw physical inputs, such as steel and cement as well as increased costs of components manufactured from these inputs (*e.g.*, transformers, turbines, pumps); (2) shop and fabrication capacity for manufactured components (relative to current demand); (3) the cost of construction field labor, both unskilled and craft labor; and (4) the market for large construction project management, *i.e.*, the queuing and bidding for projects. This section will discuss each of these factors.

Material Input Costs

Utility construction projects involve large quantities of steel, aluminum and copper (and components manufactured from these metals) as well as cement for foundations, footings and structures. All of these commodities have experienced substantial recent price increases, due to increased domestic and global demands as well as increased energy costs in mineral extraction, processing and transportation. In addition, since many of these materials are traded globally, the recent performance of the U.S. dollar will impact the domestic costs (see box on page 14).

Metals

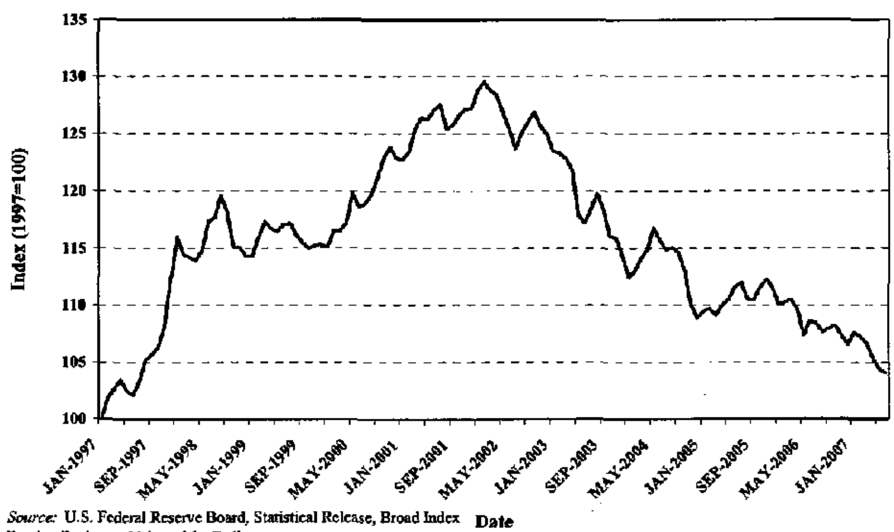
After being relatively stable for many years (and even declining in real terms), the price of various metals, including steel, copper and aluminum, has increased significantly in the last few years. These increases are primarily the result of high global demand and increased production costs (including the impact of high energy prices). A weakening U.S. dollar has also contributed to high domestic prices for imported metals and various component products.

Figure 5 shows price indices for primary inputs into steel production (iron and steel scrap, and iron ore) since 1997. The price of both inputs fell in real terms during the late 1990s, but rose sharply after 2002. Compared to the 20-percent increase in the general inflation rate (GDP deflator) between 1997 and 2006, iron ore prices rose 75 percent and iron and steel scrap prices rose nearly 120 percent. The increase over the last few years was especially sharp—between 2003 and 2006, prices for iron ore rose 60 percent and iron and scrap steel rose 150 percent.

Exchange Rates

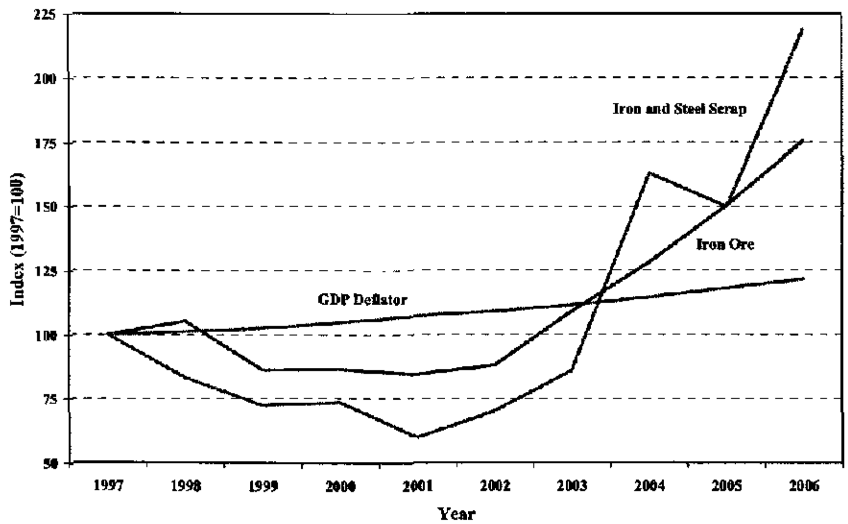
Many of the raw materials involved in utility construction projects (e.g., steel, copper, cement), as well as many major manufactured components of utility infrastructure investments, are globally traded. This means that prices in the U.S. are also affected by exchange rate fluctuations, which have been adverse to the dollar in recent years. The chart below shows trade-weighted exchange rates from 1997. Although the dollar appreciated against other currencies between 1997 and 2001, the graph also clearly shows a substantial erosion of the dollar since the beginning of 2002, losing roughly 20 percent of its value against other major trading partners' currencies. This has had a substantial impact on U.S. material and manufactured component prices, as will be reflected in many of the graphs that follow.

Nominal Broad Dollar Index



Source: U.S. Federal Reserve Board, Statistical Release, Broad Index Foreign Exchange Value of the Dollar.

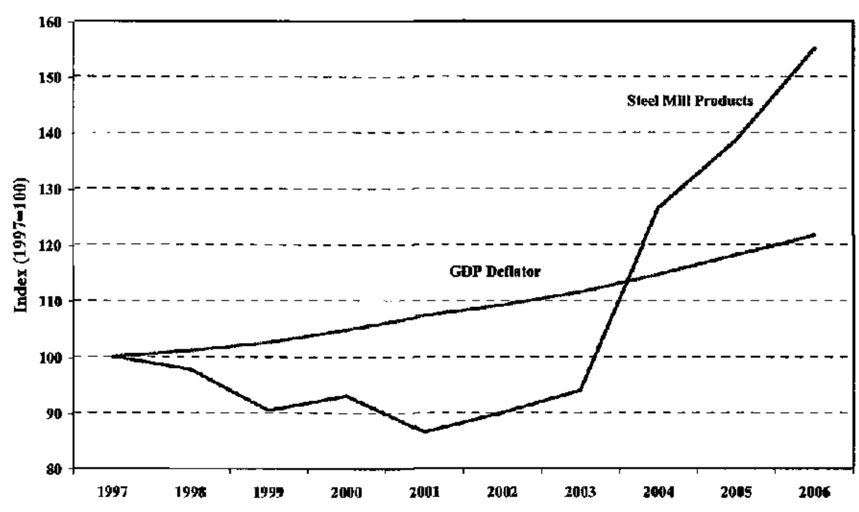
Figure 5
Inputs to Iron and Steel Production Cost Indices



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

The increase in input prices has been reflected in steel mill product prices. Figure 6 compares the trend in steel mill product prices to the general inflation rate (using the GDP deflator) over the past 10 years. Figure 6 shows that the price of steel has increased about 60 percent since 2003.

Figure 6
Steel Mill Products Price Index



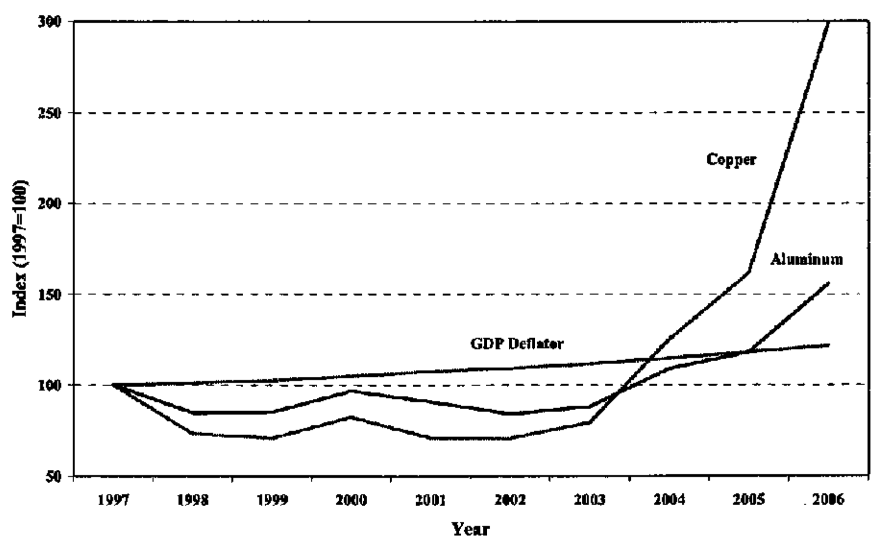
Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

Various sources point to the rapid growth of steel production and demand in China as a primary cause of the increases in both steel prices and the prices of steelmaking inputs.[11] China has become both the world's largest steelmaker and steel consumer. In addition, some analysts contend that steel companies have achieved greater pricing power, partly due to ongoing consolidation of the industry, and note that recently increased demand for steel has been driven largely by products used in energy and heavy industry, such as plate and structural steels.

From the perspective of the steel industry, the substantial and at least semi-permanent rise in the price of steel has been justified by the rapid rise in the price of many steelmaking inputs, such as steel scrap, iron ore, coking coal, and natural gas. Today's steel prices remain at historically elevated levels and, based on the underlying causes for high prices described, it appears that iron and steel costs are likely to remain at these high levels at least for the near future.

Other metals important for utility infrastructure display similar price patterns: declining real prices over the first five years or so of the previous 10 years, followed by sharp increases in the last few years. Figure 7 shows that aluminum prices doubled between 2003 and 2006, while copper prices nearly quadrupled over the same period.

Figure 7
Aluminum and Copper Price Indices

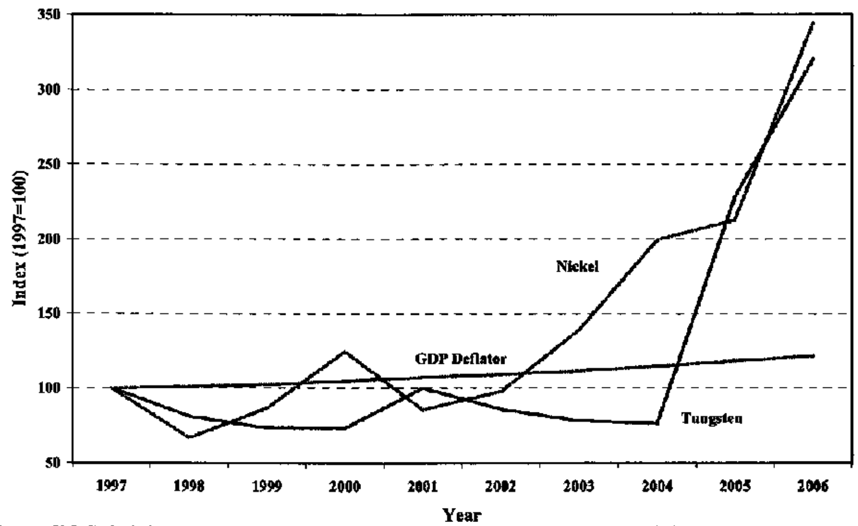


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

[11] See, for example, *Steel: Price and Policy Issues,* CRS Report to Congress, Congressional Research Service, August 31, 2006.

These price increases were also evident in metals that contribute to important steel alloys used broadly in electrical infrastructure, such as nickel and tungsten. The prices of these display similar patterns, as shown in Figure 8.

Figure 8
Nickel and Tungsten Price Indices

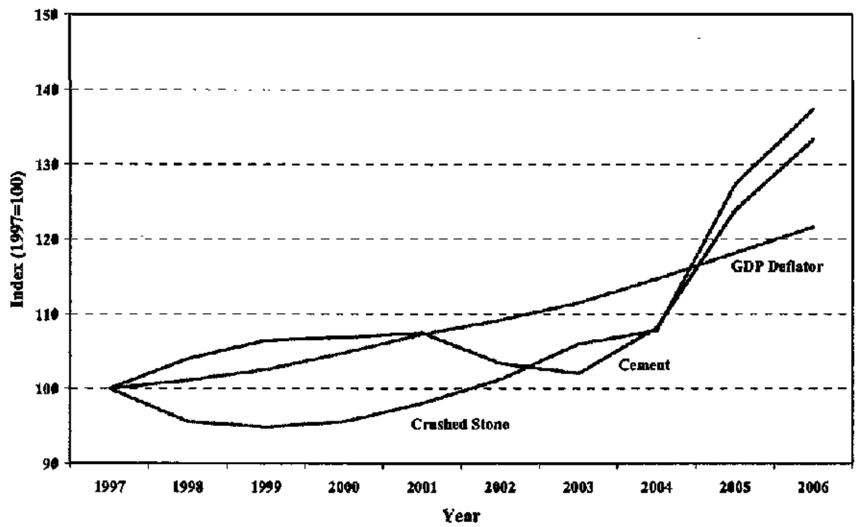


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

Cement, Concrete, Stone and Gravel

Large infrastructure projects require huge amounts of cement as well as basic stone materials. The price of cement has also risen substantially in the past few years, for the same reasons cited above for metals. Cement is an energy-intensive commodity that is traded on international markets, and recent price patterns resemble those displayed for metals. In utility construction, cement is often combined with stone and other aggregates for concrete (often reinforced with steel), and there are other site uses for sand, gravel and stone. These materials have also undergone significant price increases, primarily as a result of increased energy costs in extraction and transportation. Figure 9 shows recent price increases for cement and crushed stone. Prices for these materials have increased about 30 percent between 2004 and 2006.

Figure 9
Cement and Crushed Stone Price Indices



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

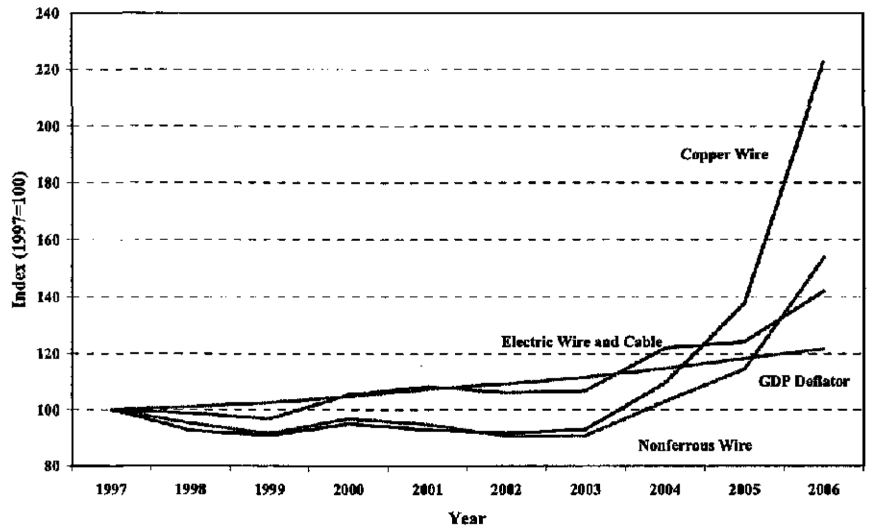
Manufactured Products for Utility Infrastructure

Although large utility construction projects consume substantial amounts of unassembled or semi-finished metal products (*e.g.*, reinforcing bars for concrete, structural steel), many of the components such as conductors, transformers and other equipment are manufactured elsewhere and shipped to the construction site. Available price indices for these components display similar patterns of recent sharp price increases.

Figure 10 shows the increased prices experienced in wire products compared to the inflation rate, according to the U.S. Bureau of Labor Statistics (BLS), highlighting the impact of underlying metal price increases.

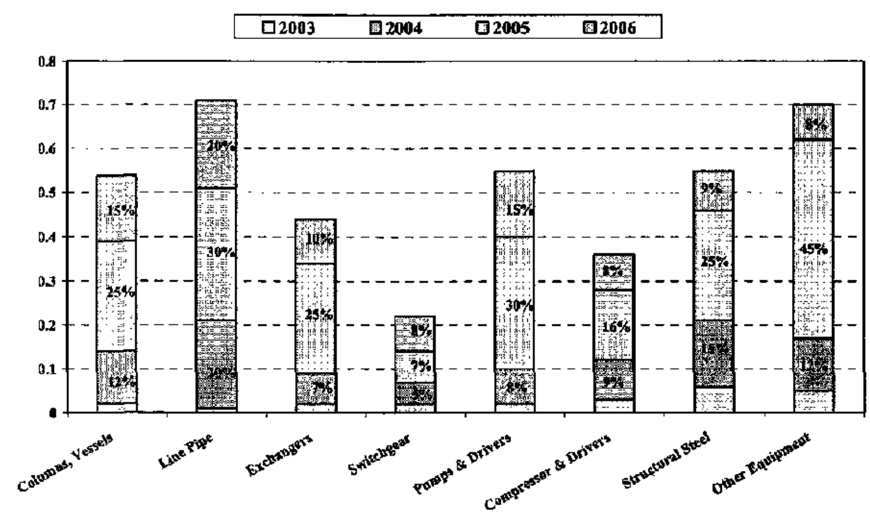
Manufactured components of generating facilities—large pressure vessels, condensers, pumps, valves—have also increased sharply since 2004. Figure 11 shows the yearly increases experienced in key component prices since 2003.

Figure 10
Electric Wire and Cable Price Indices



Sources: The U.S. Bureau of Labor Statistics and the U.S. Bureau of Economic Analysis.

Figure 11
Equipment Price Increases

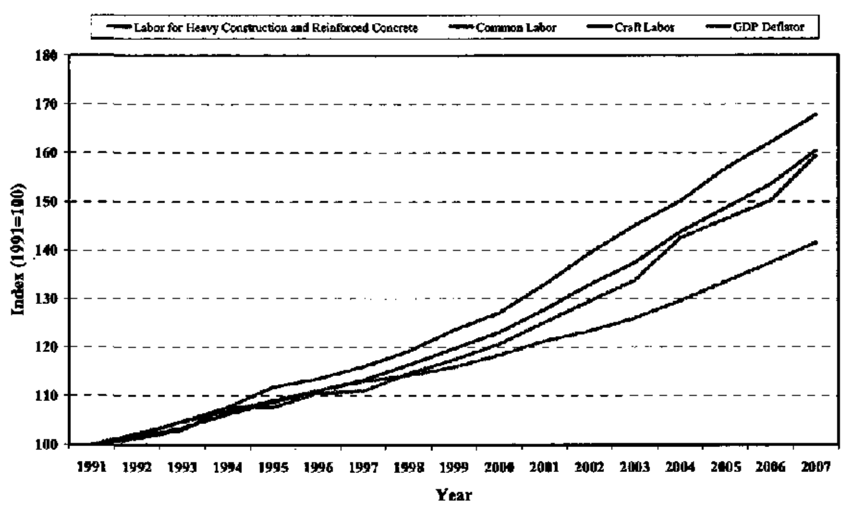


Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Labor Costs

A significant component of utility construction costs is labor—both unskilled (common) labor as well as craft labor such as pipefitters and electricians. Labor costs have also increased at rates higher than the general inflation rate, although more steadily since 1997, and recent increases have been less dramatic than for commodities. Figure 12 shows a composite national labor cost index based on simple averages of the regional Handy-Whitman Index© for common and craft labor. Between January 2001 and January 2007, the general inflation rate (measured by the GDP deflator) increased about 15 percent. During the same period, the cost of craft labor and heavy construction labor increased about 26 percent, while common labor increased 27 percent, or almost twice the rate of general inflation.[12] While less severe than commodity cost increases, increased labor costs contributed to the overall construction cost increases because of their substantial share in overall utility infrastructure construction costs.

Figure 12
National Average Labor Costs Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional labor cost indices for the specified types of labor.

Although labor costs have not risen dramatically in recent years, there is growing concern about an emerging gap between demand and supply of skilled construction labor—especially if the anticipated boom in utility construction materializes. In 2002, the Construction Users Roundtable (CURT), surveyed its members and found that recruitment, education, and retention of craft workers continue to be critical issues for the industry.[13] The average age of the current construction skilled workforce is rising rapidly, and high attrition rates in construction are compounding the problem. The industry has always had high attrition at the entry-level positions, but now many workers in the 35-40 year-old age group are leaving the industry for a variety of reasons. The latest projections indicate that, because of attrition and anticipated growth, the construction

[12] These figures represent a simple average of six regional indices, however, local and regional labor markets can vary substantially from these national averages.

[13] *Confronting the Skilled Construction Workforce Shortage.* The Construction Users Roundtable, WP-401, June 2004, p. 1.

industry must recruit 200,000 to 250,000 new craft workers per year to meet future needs. However, both demographics and a poor industry image are working against the construction industry as it tries to address this need.[14]

There also could be a growing gap between the demand and supply of electrical lineworkers who maintain the electric grid and who perform much of the labor for transmission and distribution investments. These workers erect poles and transmission towers and install or repair cables or wires used to carry electricity from power plants to customers. According to a DOE report, demand for such workers is expected to outpace supply over the next decade.[15] The DOE analysis indicates a significant forecasted shortage in the availability of qualified candidates by as many as 10,000 lineworkers, or nearly 20 percent of the current workforce. As of 2005, lineworkers earned a mean hourly wage of $25/hour, or $52,300 per year. The forecast supply shortage will place upward pressure on the wages earned by lineworkers.[16]

Shop and Fabrication Capacity

Many of the components of utility projects—including large components like turbines, condensers, and transformers—are manufactured, often as special orders to coincide with particular construction projects. Because many of these components are not held in large inventories, the overall capacity of their manufacturers can influence the prices obtained and the length of time between order and delivery. The price increases of major manufactured components were shown in Figure 11. While equipment and component prices obviously reflect underlying material costs, some of the price increases of manufactured components and the delivery lags are due to manufacturing capacity constraints that are not readily overcome in the near term.

As shown in Figure 13 and Figure 14, recent orders have largely eliminated spare shop capacity, and delivery times for major manufactured components have risen. These constraints are adding to price increases and are difficult to overcome with imported components because of the lower value of the dollar in recent years.

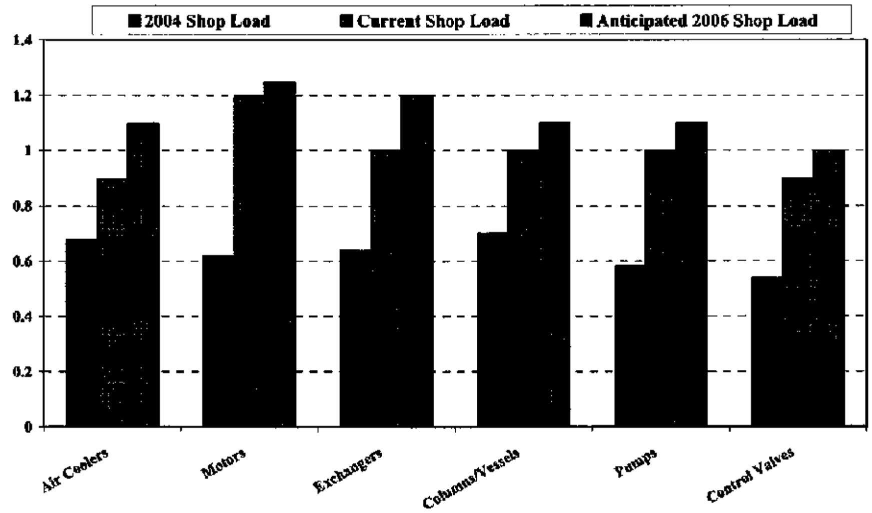
The increased delivery times can affect utility construction costs through completion delays that increase the cost of financing a project. In general, utilities commit substantial funds during the construction phase of a project that have to be financed either through debt or equity, called "allowance for fund used during construction" (AFUDC). All else held equal, the longer the time from the initiation through completion of a project, the higher is the financing costs of the investment and the ultimate costs passed through to ratepayers.

[14] *Id.*, p. 1.

[15] *Workforce Trends in the Electric Utility Industry: A Report to the United States Congress Pursuant to Section 1101 of the Energy Policy Act of 2005.* U.S. Department of Energy, August 2006, p. xi.

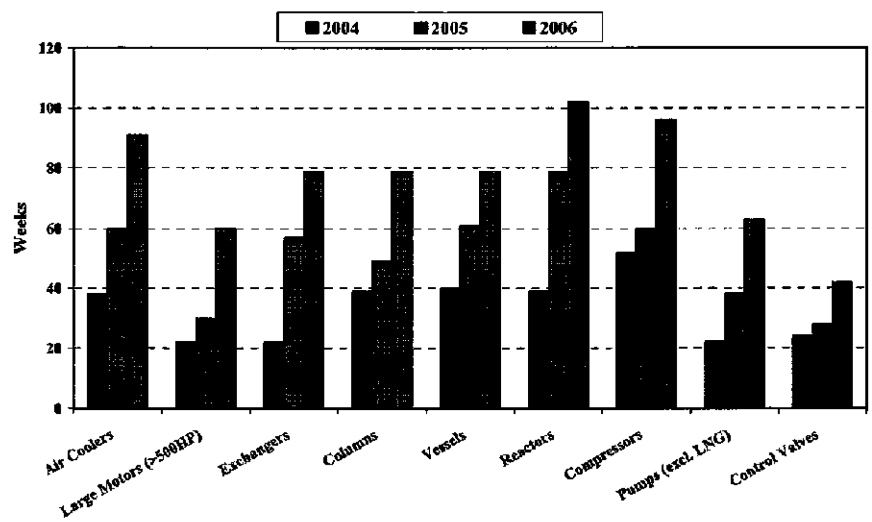
[16] *Id.*, p. 5.

Figure 13
Shop Capacity



Source: "*Who, What, Where, How*" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Figure 14
Delivery Schedules

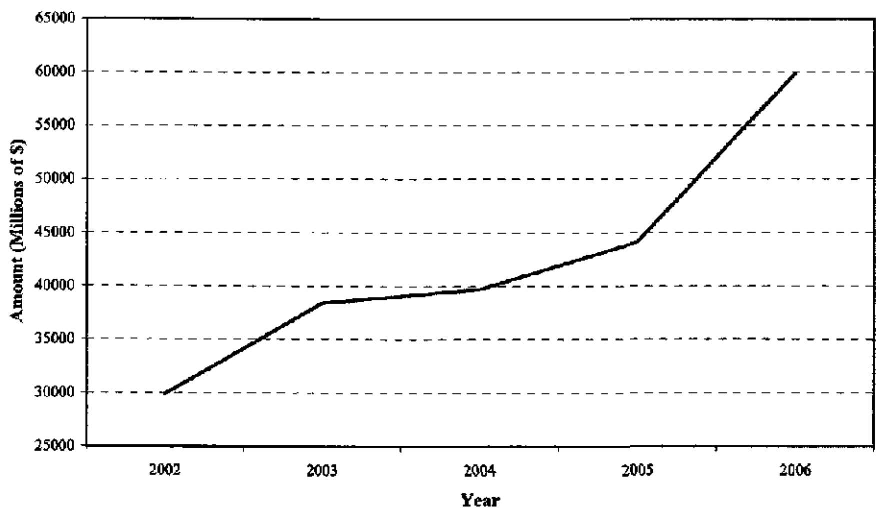


Source: "*Who, What, Where, How*" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Engineering, Procurement and Construction (EPC) Market Conditions

Increased worldwide demand for new generating and other electric infrastructure projects, particularly in China, has been cited as a significant reason for the recent escalation in the construction cost of new power plants. This suggests that major Engineering, Procurement and Construction (EPC) firms should have a growing backlog of utility infrastructure projects in the pipeline. While we were unable to obtain specific information from the major EPC firms on their worldwide backlog of electric utility infrastructure projects (*i.e.*, the number of electric utility projects compared with other infrastructure projects such as roads, port facilities and water infrastructure, in their respective pipelines), we examined their financial statements, which specify the financial value associated with their backlog of infrastructure projects. Figure 15 shows the cumulative annual financial value associated with the backlog of infrastructure projects at the following four major EPC firms; Fluor Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd. Figure 15 shows that the annual backlog of infrastructure projects rose sharply between 2005 and 2006, from $4.1 billion to $5.6 billion, an increase of 37 percent. This significant increase in the annual backlog of infrastructure projects at EPC firms is consistent with the data showing an increased worldwide demand for infrastructure projects in general and also utility generation, transmission, and distribution projects.

Figure 15
Annual Backlog at Major EPC Firms



Data are compiled from the Annual Reports of Fluor Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd. For Bechtel, the data represent new booked work, as backlog is not reported.

The growth in construction project backlogs likely will dampen the competitiveness of EPC bids for future projects, at least until the EPC industry is able to expand capacity to manage and execute greater volumes of projects. This observation does not imply that this market is generally uncompetitive—rather it reflects the limited ability of EPC firms with near-term capacity constraints to service an upswing in new project development associated with a boom period in infrastructure construction cycles. Such constraints, combined with a rapidly filling (or full) queue for project management services, limit incentives to bid aggressively on new projects.

Although difficult to quantify, this lack of spare capacity in the EPC market will undoubtedly have an upward price pressure on new bids for EPC services and contracts. A recent filing by Oklahoma Gas & Electric Company (OG&E) seeking approval of the Red Rock plant (a 950 MW coal unit) provides a demonstration of this effect. In January 2007, OG&E testimony indicated that their February 3, 2006, cost estimate of nearly $1,700/kW had been revised to more than $1,900/kW by September 29, 2006, a 12-percent increase in just nine months. More than half of the increase (6.6 percent) was ascribed to change in market conditions which "reflect higher materials costs (steel and concrete), escalation in major equipment costs, and a significant tightening of the market for EPC contractor services (as there are relatively few qualified firms that serve the power plant development market)."[17] In the detailed cost table, OG&E indicated that the estimate for EPC services had increased by more than 50 percent during the nine month period (from $223/kW to $340/kW).

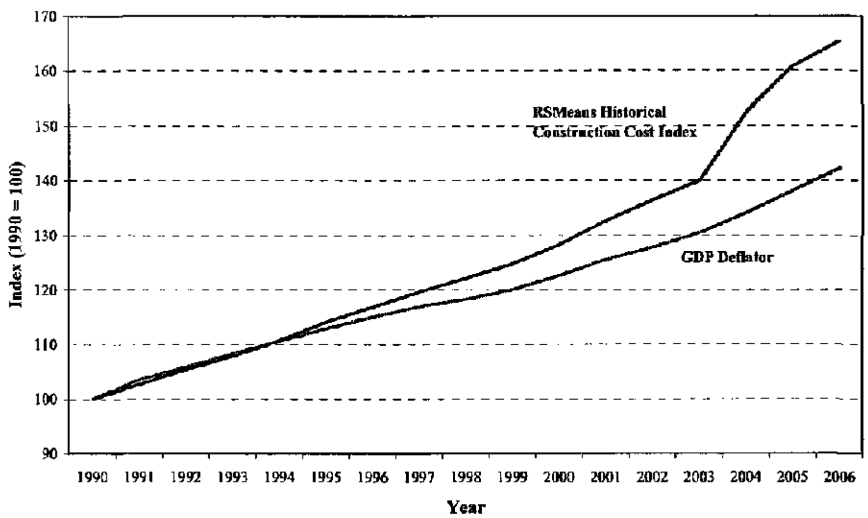
Summary Construction Cost Indices

Several sources publish summary construction cost indices that reflect composite costs for various construction projects. Although changes in these indices depend on the actual cost weights assumed *e.g.*, labor, materials, manufactured components, they provide useful summary measures for large infrastructure project construction costs.

The RSMeans Construction Cost Index provides a general construction cost index, which reflects primarily building construction (as opposed to utility projects). This index also reflects many of the same cost drivers as large utility construction projects such as steel, cement and labor. Figure 16 shows the changes in the RSMeans Construction Cost index since 1990 relative to the general inflation rate. While the index rose slightly higher than the GDP deflator beginning in the mid 1990s, it shows a pronounced increase between 2003 and 2006 when it rose by 18 percent compared to the 9 percent increase in general inflation.

[17] Testimony of Jesse B. Langston before the Corporation Commission of the State of Oklahoma, Cause No. PUD 200700012, January 17, 2007, page 27 and Exhibit JBL-9.

Figure 16
RSMeans Historical Construction Cost Index



Source: RSMeans, Heavy Construction Cost Data, 20th Annual Edition, 2006.

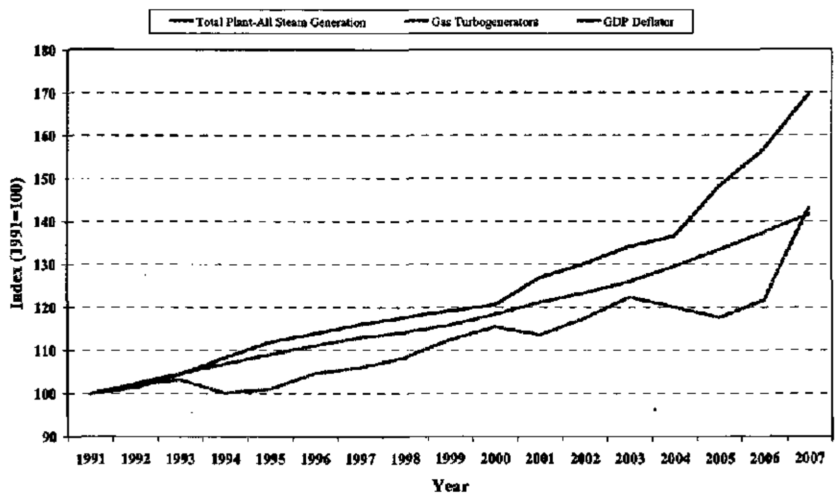
The Handy-Whitman Index© publishes detailed indices of utility construction costs for six regions, broken down by detailed component costs in many cases. Figures 17 through 19 show the evolution of several of the broad aggregate indices since 1991 compared with the general inflation index (GDP deflator).[18] The index numbers displayed on the graphs are for January 1 of each year displayed.

Figure 17 displays two indices for generation costs: a weighted average of coal steam plant construction costs (boilers, generators, piping, etc.) and a stand-alone cost index for gas combustion turbines.

As seen on Figure 17, steam generation construction costs tracked the general inflation rate fairly well through the 1990s, began to rise modestly in 2001, and increased significantly since 2004. Between January 1, 2004, and January 1, 2007, the cost of constructing steam generating units increased by 25 percent—more than triple the rate of inflation over the same time period. The cost of gas turbogenerators (combustion turbines), on the other hand, actually fell between 2003 and 2005. However, during 2006, the cost of a new combustion turbine increased by nearly 18 percent—roughly 10 times the rate of general inflation.

[18] Used with permission. See Handy-Whitman© Bulletin, No. 165 for detailed data breakouts and regional values for six regions: Pacific, Plateau, South Central, North Central, South Atlantic and North Atlantic. The Figures shown reflect simple averages of the six regions.

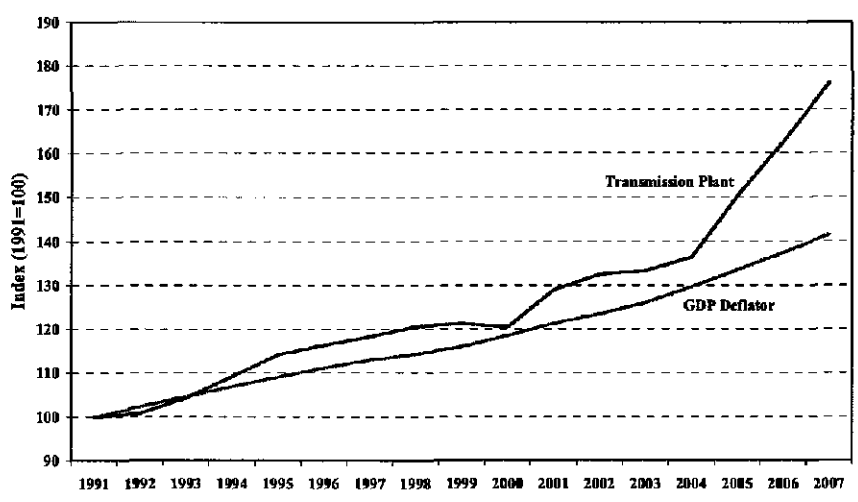
Figure 17
National Average Generation Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indices for the specified components.

Figure 18 displays the increased cost of transmission investment, which reflects such items as towers, poles, station equipment, conductors and conduit. The cost of transmission plant investments rose at about the rate of inflation between 1991 and 2000, increased in 2001, and then showed an especially sharp increase between 2004 and 2007, rising almost 30 percent or nearly four times the annual inflation rate over that period.

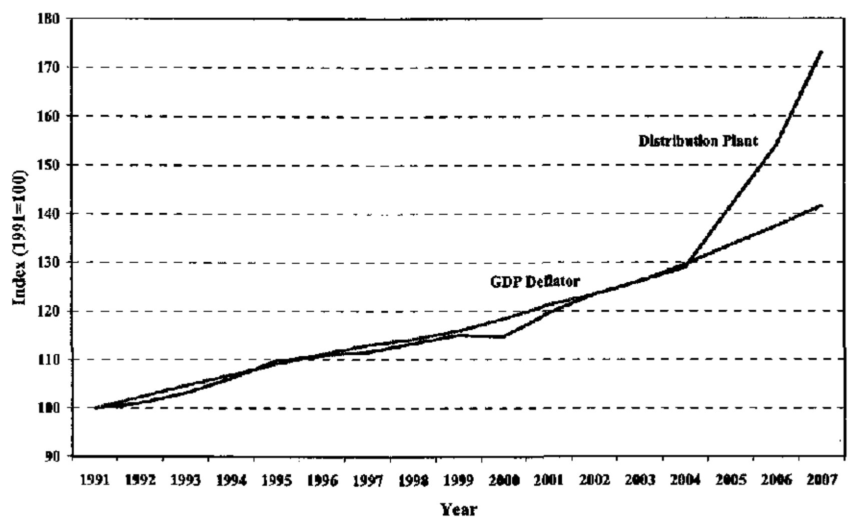
Figure 18
National Average Transmission Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional transmission cost indices.

Figure 19 shows distribution plant costs, which include poles, conductors, conduit, transformers and meters. Overall distribution plant costs tracked the general inflation rate very closely between 1991 and 2003. However, it then increased 34 percent between January 2004 and January 2007, a rate that exceeded four times the rate of general inflation.

Figure 19
National Average Distribution Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional distribution cost indices.

Comparison with Energy Information Administration Power Plant Cost Estimates

Every year, EIA prepares a long-term forecast of energy prices, production, and consumption (for electricity and the other major energy sectors), which is documented in the *Annual Energy Outlook* (AEO). A companion publication, *Assumptions to the Annual Energy Outlook*, itemizes the assumptions (*e.g.*, fuel prices, economic growth, environmental regulation) underlying EIA's annual long-term forecast. Included in the latter document are estimates of the "overnight" capital cost of new generating units *(i.e.,* the capital cost exclusive of financing costs). These cost estimates influence the type of new generating capacity projected to be built during the 25-year time horizon modeled in the AEO.

The EIA capital cost assumptions are generic estimates that do not take into account the site-specific characteristics that can affect construction costs significantly.[19] While EIA's estimates do not necessarily provide an accurate estimate of the cost of building a power plant at a specific location, they should, in theory, provide a good "ballpark" estimate of the relative construction cost of different generation

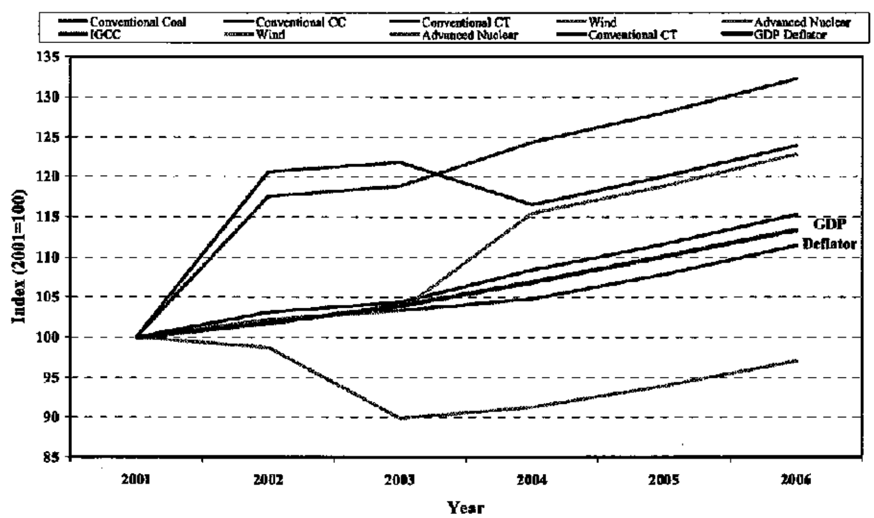
[19] EIA does incorporate regional multipliers to reflect minor variations in construction costs based on labor conditions.

technologies at any given time. In addition, since they are prepared annually, these estimates also should provide insight into construction cost trends over time.

The EIA plant cost estimates are widely used by industry analysts, consultants, academics, and policymakers. These numbers frequently are cited in regulatory proceedings, sometimes as a yardstick by which to measure a utility's projected or incurred capital costs for a generating plant. Given this, it is important that EIA's numbers provide a reasonable estimate of plant costs and incorporate both technological and other market trends that significantly affect these costs.

We reviewed EIA's estimate of overnight plant costs for the six-year period 2001 to 2006. Figure 20 shows EIA's estimates of the construction cost of six generation technologies—combined-cycle gas-fired plants, combustion turbines (CTs), pulverized coal, nuclear, IGCC, and wind—over the period 2001 to 2006 and compares these projections to the general inflation rate (GDP deflator). These six technologies, generally speaking, have been the ones most commonly built or given serious consideration in utility resource plans over the last few years. Thus, we can compare the data and case studies discussed above to EIA's cost estimates.

Figure 20
EIA Generation Construction Cost Estimates



Sources: Data collected from the Energy Information Administration, *Assumptions to the Annual Energy Outlook 2002 to 2007* and from the U.S. Bureau of Economic Analysis.

The general pattern in Figure 20 shows a dramatic change in several technology costs between 2001 and 2004 followed by a stable period of growth until 2006. The two exceptions to this are conventional coal and IGCC, which increase by a near constant rate each year close to the rate of inflation throughout the period. The data show conventional CC and conventional CT experiencing a sharp increase between 2001 and 2002. After this increase, conventional CC levels off and proceeds to increase at a pace near inflation, while conventional CT actually drops significantly before 2004 when it too levels near the rate of inflation. The pattern seen with nuclear technology is near to the opposite. It falls dramatically until about 2003 and then increases at the same rate as the GDP deflator. Lastly, wind moves close to inflation until 2004 when it experiences a one-time jump and then flattens off through 2006.

These patterns of cost estimates over time contradict the data and findings of this report. Almost every other generation construction cost element has shown price changes at or near the rate of inflation throughout the early part of this decade with a dramatic change in only the last few years. EIA appears to have reconsidered several technology cost estimates (or revised the benchmark technology type) in isolation between 2001 and 2004, without a systematic update of others. Meanwhile, during the period that overall construction costs were rising well above the general inflation rate, EIA has not revised its estimated capital cost figures to reflect this trend.

EIA's estimates of plant costs do not adequately reflect the recent increase in plant construction costs that has occurred in the last few years. Indeed, EIA itself acknowledges that its estimated construction costs do not reflect short-term changes in the price of commodities such as steel, cement and concrete.[20] While one would expect some lag in the EIA data, it is troubling that its most recent estimates continue to show the construction cost of conventional power plants increasing only at the general rate of inflation. Empirical evidence shows that the construction cost of generating plants—both fossil-fired and renewable—is escalating at a rate well above the GDP deflator. Even the most recent EIA data fail to reflect important market impacts that are driving plant construction costs, and thus do not provide a reliable measure of current or expected construction costs.

[20] *Annual Energy Outlook 2007*, U.S. Energy Information Administration, p. 36.

Conclusion

Construction costs for electric utility investments have risen sharply over the past several years, due to factors beyond the industry's control. Increased prices for material and manufactured components, rising wages, and a tighter market for construction project management services have contributed to an across-the-board increase in the costs of investing in utility infrastructure. These higher costs show no immediate signs of abating.

Despite these higher costs, utilities will continue to invest in baseload generation, environmental controls, transmission projects and distribution system expansion. However, rising construction costs will put additional upward pressure on retail rates over time, and may alter the pace and composition of investments going forward. The overall impact on the industry and on customers, however, will be borne out in various ways, depending on how utilities, markets and regulators respond to these cost increases. In the long run, customers ultimately will pay for higher construction costs—either directly in rates for completed assets of regulated companies, less directly in the form of higher energy prices needed to attract new generating capacity in organized markets and in higher transmission tariffs, or indirectly when rising construction costs defer investments and delay expected benefits such as enhanced reliability and lower, more stable long-term electricity prices.

BEFORE THE
OHIO POWER SITING BOARD

Application of American Municipal Power,	)	
Ohio, Inc. (AMP-Ohio) for a Certificate of	)	
Environmental Compatibility and Public	)	Case No. 06-1358-EL-BGN
For the American Municipal Power	)	
Generating Station in Meigs County, Ohio	)	

DIRECT TESTIMONY OF
RICHARD C. FURMAN

ON BEHALF OF

NATURAL RESOURCES DEFENSE COUNCIL
OHIO ENVIRONMENTAL COUNCIL
SIERRA CLUB

October 25, 2007

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Table of Exhibits

I. BACKGROUND AND WORK EXPERIENCE

Q. Please State Your Name and Address for the Record.

A: My name is Richard C. Furman. My address is 10404 S.W. 128 Terrace, Perrine, Florida 33176.

Q: What Is Your Occupation?

A: I am a retired consulting engineer, and I volunteer my time to advise utilities, government agencies, environmental groups and the public about the potential benefits of using coal gasification technologies. I have testified in previous permit hearings for proposed coal plants concerning emission control technologies, applicable emission regulations and alternative technologies concerning Mercury, NO_x, SO_2, particulate and CO_2 emissions and their associated costs.

Q: How Long Have You Been Retired?

A: Since February 2003.

Q: What Was Your Occupation Before You Retired?

A: During my entire engineering career, I have worked on new energy technologies, alternative fuels for power plants, and pollution control for power plants. Prior to my retirement, I was an independent consulting engineer for 22 years to various utility companies, government agencies, process developers and research organizations on the development, technical feasibility and application of new energy technologies and alternative fuels for power plants.

Q: What Did You Do Before You Were An Independent Consulting Engineer?

A: Prior to my work as a consulting engineer, I managed Florida Power & Light's coal conversion program and fuels research and development program, which included the first conversion of a 400 megawatt (400MW) power plant from oil to a coal-oil mixture to reduce oil consumption after the second oil embargo. Prior to this, I directed the engineering study for the conversion of New England Electric's Brayton Point Power Plant, which was the first major conversion of a power plant from oil to coal after the first oil embargo.

My first engineering job was working for Southern California Edison Company to modify their power plants for two-stage combustion to reduce nitrogen oxide emissions in 1969.

Q: Please Summarize Your Formal Education.

A: I received my B.S. in Chemical Engineering from Worcester Polytechnic Institute in 1969 and a M.S. in Chemical Engineering from Massachusetts Institute of Technology in 1972. I was a researcher at MIT for the book entitled <u>New Energy Technologies</u> by Hottel and Howard. After researching for this book, I decided to do my Master's thesis on coal gasification because of its potential as a future energy source and its environmental benefits. My Master's thesis at MIT was entitled <u>Technical and Economic Evaluation of Coal Gasification Processes</u>. I was also a teaching assistant at MIT for the courses of <u>Principles of Combustion and Air Pollution</u> and <u>Seminar in Air Pollution Control</u>. A copy of my resume is attached as Exhibit RCF-1.

Q: How Does Your Education and Experience Prepare You to Provide Expert Testimony in this Case?

A: Both my education and work have required an in-depth understanding of past, present and new forms of energy technologies that can be used for power plants. My education and work experiences also involved an in-depth understanding of all the various fuels for power plants including the different types of coals, fuel oils, natural gas, petroleum coke, synthesis gas, biomass and refinery wastes. My graduate education and subsequent work experiences have provided me with a detailed understanding of the techniques and costs for controlling power plant pollution including mercury, NO_x, SO_2, CO, particulate matter and CO_2 emissions. My prior work for 3 major electric utility companies allowed me to make use of this knowledge to help develop and utilize new fuels and emission control technologies for power plants. My current volunteer experience allows me to keep informed about the latest developments in new energy technologies, coal gasification technologies, fuels for power plants, techniques for controlling power plant emissions, costs associated with the application of these technologies for power plants and the development of new technologies that may be applicable to power plants.

II. SUMMARY OF TESTIMONY

Q: What Is Your Expert Opinion About the Proposed Pulverized Coal Plant?

A: The proposed pulverized coal (PC) plant does not represent the minimum adverse environmental impact, considering the state of available technology and the nature and economics of the various alternatives. My testimony shows that an IGCC plant can eliminate between 40 and 93% of the various air pollutants that the proposed PC plants will emit. Various studies have shown that IGCC plants can capture CO_2 at much lower costs than pulverized coal plants. My testimony shows how an IGCC plant can provide electricity at a lower cost than a PC plant. Many utilities around the country are choosing IGCC plants due to IGCC's much lower emissions of all pollutants and its capability to capture CO_2.

The proposed pulverized coal (PC) plant does not serve the public interest, convenience and necessity due to the adverse risks that these PC plants have for significant increases in costs and water consumption to meet future environmental regulations. My testimony shows that, in comparison to a pulverized coal plant, IGCC technology allows for the production of power from coal with significant fewer environmental impacts, and provides the best option for C02 emissions reduction on a coal power plant. Studies by the US Department of Energy, US Environmental Protection Agency, the Electric Power Research Institute, major universities and the electric power industry's engineering firms have concluded that both capital costs and the cost of electricity are lower for IGCC technology with C02 capture than for any other coal based generating technology.

The proposed pulverized coal (PC) plants do not incorporate the maximum feasible water conservation practices. After considering the available technologies and the nature and economics of the various alternatives my testimony shows that the proposed design for the AMPS-Ohio plants will consume 55% more water than the same size IGCC plant. If CO2 capture is required the water consumption for the proposed AMPS-Ohio plant will likely be 200% higher than an IGCC plant with CO2 capture. These are significant additional financial and environmental risks caused by the proposed PC plants.

IGCC's advantage arises from the fact that the C02 and other pollutants are captured prior to combustion. This allows the removal from the much smaller volume of syngas prior to combustion rather than the much larger volume of flue gas after combustion. Prior to combustion the syngas is under high pressure and does not contain the large quantities of atmospheric nitrogen that is present in the post-combustion flue gas. Both of these factors make the volume of the flue gas more than 100 times larger than the volume of the syngas. The equipment necessary for emission control on an IGCC unit is smaller because there is a small volume of gas to be processed relative to post combustion flue gas.

Various studies have shown that CO2 capture would be less costly from an IGCC plant than from a PC plant. The most recent and comprehensive studies on CO2 capture and storage are:

The Future of Coal, by the Massachusetts Institute of Technology (MIT), published in April 2007 and the Cost and Performance Baseline for Fossil Energy Plants, by the Department of Energy's (DOE) National Energy Technology Laboratory (NETL), published on May 15, 2007. This NETL study shows that CO2 capture and storage will increase the cost of electricity by 85% for the AMPS-Ohio plant (Sub-critical PC design). This same study indicates that CO2 capture and storage will increase the cost of electricity by 32% for an IGCC plant. This much higher cost for CO2 capture from the proposed AMPS-Ohio plant is a significant financial risk.

For IGCC plants, the processes and technology required to capture CO2 from syngas are known and currently being used commercially at numerous industrial, non-power generation gasification facilities around the world. In addition, the processes and technology required to inject CO2 into deep geologic formations are also currently being used at several sites, including the Dakota Gasification Plant in Beulah, North Dakota, which currently sells over 1 million tons per year of CO2 for use in enhanced oil recovery.

While it is true that there are no operating IGCC power plant facilities currently capturing CO_2 for geologic injection , all of the technical issues associated with CO_2 capture and injection at an IGCC power plant have been commercially demonstrated at other, non-power plant gasification facilities. Installation of CO2 capture equipment at IGCC plants has not occurred due primarily to the cost of the equipment, the impact to the unit's operation and the belief that there is no regulatory requirement to control CO2 emissions.

No method of CO_2 capture is commercially available or economically viable for the proposed pulverized coal power plants. Research & Development (R&D) has only started on technology that may be capable of capturing CO_2 from Pulverized Coal (PC) plants. It will take many years before these R&D projects determine if these new technologies are technically and economically feasible at commercial scale.

The recent DOE report Cost and Performance Baseline for Fossil Energy Plants, by the NETL, May 15, 2007 shows that the proposed design for the AMPS-Ohio will consume 55% more water than the same size IGCC plant. This study also indicates that if CO2 capture is required the water consumption for the proposed AMPS-Ohio plant will require 200% more water than an IGCC plant with CO2 capture. These are significant additional financial and environmental risks caused by the proposed PC plants.

My testimony presents comparisons of recent permit applications for IGCC plants versus the proposed AMPS-Ohio PC plants that show significantly lower emissions for the IGCC plants. My testimony also presents comparisons of recent permit applications for other PC plants versus the proposed AMPS-Ohio PC plants that show lower emissions for the other PC plants. Therefore the proposed AMP-

Ohio plant does not have the minimum adverse environmental impact possible.

Commercial IGCC plants have been in operation in the U.S. for more than 10 years. Chuck Black, the president of Tampa Electric Company, was quoted in Time Magazine (November 2006) as saying **"it's our least cost-generating resources, so we count on it and use it every day as part of our system"**. Today there are approximately 130 gasification plants worldwide that produce fertilizers, fuels, steam, hydrogen and other chemicals, and electricity. Of these 130 plants, seventeen are IGCC plants. These IGCC plants have a capacity of about 4,000 MW(net) and have almost one million hours of operation.

The Great Plains Synfuels Plant has been gasifying coal since 1984 to produce synthetic natural gas (SNG). Since 2000 this gasification plant has been capturing its CO_2 and transporting it 205 miles by a new pipeline where it is injected underground in connection with enhanced oil recovery. This demonstrates that CO_2 can be captured, compressed, and transported from a commercial gasification plant for geologic injection.

The Eastman Chemical Company has been removing the mercury from their gasification plant for more than 20 years. Recent testing indicates that the mercury levels in the cleaned gas are at non-detectable levels. This level of mercury removal can not be obtained from PC plants.

IGCC plants are capable of using lower cost fuels including petroleum coke (petcoke), biomass wastes and renewable energy crops.

IGCC plants produce less solid wastes and less potential for ground water contamination than the proposed pulverized coal plant.

III. PULVERIZED COAL COMBUSTION AND GASIFICATION TECHNOLOGIES

Q. What are the Differences Between Combustion and Gasification?

A: It is important to understand the difference between combustion which is used in a coal power plant and coal gasification which is used in an IGCC plant. Exhibit RCF-2 shows the differences between combustion and gasification. The coal boiler operates at 1800 F and atmospheric pressure. The coal gasifier operates at 2600 F and 40 atmospheres pressure. The flow meters show the pounds of material that need to be processed for the same amount of electricity. Prior to gasification the nitrogen is separated from the air and the oxygen alone is used in the gasifier. Therefore for the same amount of electricity the gasifier produces 173 pound of synthesis gas versus 1000 pounds of exhaust gas from the boiler. Since the gasifier operates at higher pressure there is also a much smaller volume of gas that needs to be treated for pollutants and therefore the size of the equipment and capital cost is much smaller. The exhaust gas volume that needs to be treated from a coal boiler is 160 times larger than the volume of the synthesis gas that can also be cleaned of pollutants. The form of the pollutants from the gasifier makes it possible for very efficient recovery of potential pollutants using proven commercially available equipment that is operating in the natural gas and petrochemical industries. Proven commercially available technologies are <u>not</u> presently available for the proposed new coal boilers for mercury and CO_2. This is one of the main reasons that gasification is a better option..

Q. What Is Integrated Gasification Combined Cycle (IGCC)?

A. Integrated Gasification Combined Cycle (IGCC) is the efficient integration of the coal gasification process with the pre-combustion removal of pollutants and the generation of electricity using a combined cycle power plant. Due to the high pressure and low volume of the concentrated synthesis gas that is produced it is capable of higher levels of pollutant removal at lower costs than pulverized coal (PC) combustion.

Exhibit RCF-3 shows the various parts of an IGCC plant that will be described.

IGCC is a method of producing electricity from coal and other fuels. In an IGCC plant, coal is first converted to synthesis gas (also called syngas) composed primarily of hydrogen, carbon monoxide and carbon dioxide. After removing particulate matter, sulfur, mercury and other pollutants, the cleaned syngas is combusted in a combined-cycle power plant to produce electricity.

In the first step of the IGCC process, coal is slurried with either water or nitrogen and enters the gasifier. It is mixed with oxygen, not air, which is provided to the gasifier from an air separation unit. The coal is partially oxidized at high temperature and pressure to form syngas. The syngas leaves the gasifier, while the solids are removed from the bottom of the gasifier. The operating conditions in the gasifier vitrify the solids. In other words, the solids are encased in a glass-like substance that makes them less likely to leach into groundwater when disposed of in a landfill as compared to solid wastes from a conventional coal plant.

After leaving the gasifier, the syngas undergoes several clean-up operations. Particulate matter is removed. Next, a carbon bed can be used to take out mercury. Finally, sulfur (in the form of H2S) is removed from the syngas in a combination of steps that usually involve hydrolysis followed by an adsorption operation using MDEA (methyldiethanolamine) or Selexol. The

H2S that is removed from the syngas is converted into commercial-grade sulfur or sulfuric acid which are sold as byproducts.

The clean syngas enters a combustion turbine where it is burned to produce electricity. The heat from the exhaust gases is captured in a heat recovery steam generator (HRSG) and the resulting steam is used to produce more electricity. The combustion turbine, combined with the HRSG, is the same configuration commonly used for natural gas combined cycle (NGCC) plants. In Europe and Japan, some IGCC units have installed selective catalytic reduction (SCR) to control nitrous oxides (NO_x) emissions from the turbine, but in the United States, NO_x emissions at existing IGCC plants have been reduced with diluent injection only. The majority of recent final permits for IGCC plants in the U.S. have included SCR for lower NOx emissions. (Source: Air Construction/Prevention of Significant Deterioration Permit Application for Tampa Electric Polk Unit #6, prepared by Environmental Consulting & Technology, September 2007, Table 5-2).

Q: What are the Other Advantages of Using Gasification Plants?

A: Gasification, which is also called Partial Oxidation, can use a wide range of fuels and can produce a wide range of products as shown in Exhibit RCF-4.

The fuel flexibility of gasification is demonstrated by its ability to use all types of coal, petroleum coke, biomass, refinery wastes, and waste materials. The synthesis gas that is produced consists of mainly carbon monoxide (CO) and hydrogen (H2) which are used as the raw materials to produce (or synthesis) a wide range of chemicals. This synthesis gas can also be used as fuel directly for a combined cycle power plant called an IGCC (Integrated Gasification

Combined Cycle) plant. It can be further processed in a shift reactor to produce hydrogen and carbon dioxide (CO_2). The hydrogen can be used as a fuel or used to improve fuel quality in a refinery. The CO_2 can be used for enhanced oil recovery to produce addition oil from aging oil fields. This demonstrates the wide range of products that can be produced by gasification. The production of multiple products from a single plant is called polygeneration. Economic analyses have indicated that polygeneration of fuels, chemicals and electricity improves the profitability of gasification plants.

IV. COST OF ELECTRICITY FROM PULVERIZED COAL AND IGCC PLANTS (With and Without CO_2 Capture)

Q. What Do the Most Recent Studies Conclude About the Cost of Electricity from New IGCC Plants and New Pulverized Coal Plants?

A. The most recent and comprehensive studies on the costs of electricity from new IGCC plants and new PC plants are:

The Future of Coal, by the Massachusetts Institute of Technology (MIT), April 2007 and Cost and Performance Baseline for Fossil Energy Plants, by the Department of Energy's (DOE) National Energy Technology Laboratory (NETL), May 15, 2007.

Exhibit RCF-5 is from the MIT Report The Future of Coal. This exhibit shows the relative cost of electricity (COE) from PC and IGCC plants both without and with CO2 capture. To validate their study the MIT report compared their results with the COE estimates from three other sources and summarized the results as shown in Exhibit RCF-5. This MIT exhibit uses the PC plant without CO2 capture as the reference case at a value of 1.0. This exhibit shows that MIT's COE from an IGCC plant is only 5% higher than the

COE from a PC plant. Therefore the significant emission reductions by using IGCC will only increase the cost of electricity production by 5%. It should be noted that this comparison is without CO2 capture and using Illinois #6 Bituminous coal for both cases. Exhibit RCF-5 also shows that when CO2 capture is considered, the COE produced by the PC plant is increased by 60% while the COE produced by the IGCC plant is only increased by 30%.

IGCC plants are capable of using lower cost fuels including petroleum coke (petcoke), biomass wastes and renewable energy crops. PC plants are limited to only small amounts of these lower cost fuels due to their combustion characteristics. The Cost of Electricity (COE) can be reduced significantly by utilizing lower cost fuels for the IGCC plants.

Q. Do Other Studies Confirm this Conclusion of Significantly Lower Costs for Capturing CO_2 in IGCC Plants than PC plants?

A: Yes.

Exhibit RCF-5 shows the results of studies performed by the Gasification Technology Council (GTC), American Electric Power (AEP) and General Electric (GE) which all show that IGCC plants will be more cost effective than PC plants when carbon reductions are required. IGCC plants are capable of capturing CO_2 at much lower costs than pulverized coal plants.

Exhibit RCF-6 is from the recent Department of Energy's (DOE) National Energy Technology Laboratory (NETL) report Cost and Performance Baseline for Fossil Energy Plants, May 15, 2007. This exhibit shows the levelized cost of electricity for IGCC, PC and natural gas combined cycle (NGCC) plants without and with CO2 capture and sequestration. The proposed AMPS-Ohio plant would be classified as Subcritical PC and this exhibit shows the COE without carbon capture and sequestration (w/o CCS) and with carbon capture and sequestration (w/ CCS).

This exhibit shows that without CCS the PC plants have the lowest COE. The disadvantages of these PC plants are their significantly higher emissions and much higher costs for CCS. Exhibit RCF-6 indicates that CO2 capture and storage will increase the cost of electricity by 85% for the AMPS-Ohio plant (Subcritical PC design). This same study indicates that CO2 capture and storage will increase the cost of electricity by 32% for an IGCC plant. This much higher cost for CO2 capture from the proposed AMPS-Ohio plant is a significant financial risk.

The capture, transport and injection of CO_2 is being doneon a commercial scale at the Great Plains Synfuels Plant which will be described in later testimony. CO2 capture from coal derived syngas is a commercially proven process that has been used for decades in gasification plants around the world. This technology can be applied to IGCC units to remove CO2 from the syngas prior to use in the combustion turbine.

No method of CO_2 capture is commercially available or economically viable for the proposed PC power plants. PC plants will have to capture the CO2 from the flue gas stream, which will require much larger and more expensive equipment to capture the CO2 than IGCC technology. Research & Development (R&D) has only started on technology that may be capable of capturing CO_2 from PC plants. It will take many years before these R&D projects determine if these new technologies are technically and economically feasible.

The Chilled Ammonia Process that is one of the proposed methods for capture of CO_2 from PC plants has been evaluated by DOE/NETL. (Source: <u>Chilled Ammonia-based Wet Scrubbing for Post-Combustion CO2 Capture,</u>

DOE/NETL-401/021507, February, 2007). NETL has already discontinued funding of future development of this process. NETL's testing and evaluations have indicated that this process is not capable of reaching the goals of technical and economic feasibility for commercial operation. For gasification plants the technology is already in commercial operation for CO_2 capture, transportation and injection.

Due to the future requirements to capture CO2 and the more stringent emission limits for other emissions, the IGCC plants will be less expensive to operate in the future. The net result of selecting the IGCC plant, rather than a pulverized coal plant, is lower environmental impact now and lower cost electricity in the future.

Q: Have the Environmental and Health Costs Associated with the Emissions from Electric Generation been Determined for IGCC and PC Plants?

A: Yes.

Since the emissions from a PC plant are presently allowed to be significantly higher than an IGCC plant any economic analysis should include the environmental and health costs associated with these higher emissions.

Exhibit RCF-7 compares the economic impact associated with the higher emissions from PC plants than IGCC plants. Using published data on the environmental and health costs associated with the emissions of PM, SO_2 and NOx this table compares the economic costs for IGCC and PC plants for their current emission levels. Exhibit RCF-7 shows that when the costs for the higher emissions are included, the true cost of electricity is less for the IGCC plant.

Q. Have You Compared the Cost of Electricity Produced from a New IGCC Plant using Petroleum Coke with the Cost of Electricity from a New Pulverized Coal Plant using Bituminous Coal?

A. Yes.

I prepared Exhibit RCF-8 which shows that the costs of electricity for the three types of Pulverized Coal (PC) plants are higher than the cost of electricity for an IGCC plant using Petroleum Coke (PetCoke) in Florida. The Florida location was selected for comparison because of the proposed PC plants that were being planned in Florida and the availability of petcoke costs delivered to the commercial IGCC plant at Tampa Electric. Exhibit RCF-8 shows that although the IGCC plant has a higher capital cost than the PC plants it has a significantly lower fuel cost when using petcoke. Petroleum coke is the byproduct of a refinery process used to drive-off lighter hydrocarbons from heavy residual oil. Solid petroleum coke is what is left behind. The U.S. petroleum refineries produce over 43 million tons per year of fuel-grade petcoke that can be used by IGCC plants. This petcoke can provide over 17,000 MW of new generating capacity in the U.S. At the present time most of this petcoke is exported to other countries that allow the higher emissions of SO_2 that petcoke produces. The use of petcoke in PC plants is usually limited to a maximum of 20% petcoke due to combustion and emission limitations. However IGCC can use 100% petcoke and make use of this lower cost fuel. The average price of petcoke for the past 20 years has been about half of the cost of coal. IGCC plants can effectively remove the sulfur from petcoke and sell it as a valuable byproduct. Therefore an IGCC plant utilizing petcoke is a lower cost alternative to a pulverized coal plant. For the past 10 years Tampa Electric has been using petcoke in their 250 MW IGCC plant. Tampa Electric's President Chuck Black was recently quoted as saying: "it's our least cost-generating resource, so we count on it and use it every day as part of our system" in the November 2006 issue of Time Magazine, Inside Business.

Three companies have recently announced that they plan to build petcoke IGCC plants. These are the BP Carson IGCC plant in California, the Hunton IGCC plant in Texas and the TransCanada IGCC plant in Saskatchewan, Canada.

The sources of data for Exhibit RCF-8 - Cost of Electricity Comparison Chart for Florida are:

1. Capital, O&M and all non-fuel costs are based upon: Department of Energy/NETL Presentation, Federal IGCC R&D: Coal's Pathway to the Future, by Juli Klara, presented at GTC, Oct. 4, 2006.

2. Efficiencies and fuel consumption calculations are based upon: EPA Final Report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, July 2006.

3. Fuel costs are based upon: Department of Energy, Energy Information Administration, Average Delivered Cost of Coal and Petroleum Coke to Electric Utilities in Florida, 2005 and 2004, and Tampa Electric Company's (TECO) data presented at plant tours of Polk Power Station's IGCC plant.

Q: Are Any Companies Planning to Use Petcoke With CO2 Capture and Sequestration?

A: Yes.

British Petroleum (BP) is proposing to build a 500 MW IGCC plant in the Los Angeles area that will use petroleum coke. This plant will also capture CO_2 and use the CO_2 in enhanced oil recovery (EOR) projects. Exhibit RCF-9 is a diagram of BP's IGCC project. Hunton Energy has announced a 1,200 MW IGCC project in the Houston area. The plant will use petroleum coke from a Valero refinery as fuel under a long-term supply agreement. Hunton Energy has stated the project will be designed to capture and sequester CO_2. The proposed TransCanada IGCC project will be a polygeneration facility, located in Belle Plaine, Saskatchewan, Canada, is expected to use petroleum coke as feedstock to produce hydrogen, nitrogen, steam and carbon dioxide for fertilizer production and enhanced oil recovery (EOR), and to generate approximately 300 MW of electricity. This project plans to capture and sequester over five million metric tons of carbon dioxide annually to increase local oil production.

V. AIR POLLUTANT EMISSIONS FROM PULVERIZED COAL AND IGCC PLANTS

Q: Are the Emissions from Pulverized Coal (PC) Plants Significantly Higher Than IGCC Plants? If So, Explain.

A: Yes.

Exhibit RCF-10 shows the much lower emissions that are produced from Integrated Gasification Combined Cycle (IGCC) plants than Super-critical Pulverized Coal (SCPC) plants. This exhibit is from an Electric Power Research Institute's (EPRI) presentation on June 28, 2006. It compares the emissions levels (in lb/MWh) that EPRI believes should be obtained by current state-of-the-art PC, IGCC and natural gas combined cycle (NGCC) plants . The SCPC plant design was chosen to represent the more efficient design for new PC plants. The AMPS – Ohio plant is being proposed with selective catalytic reduction (SCR) for NOx control. Therefore the relevant comparison from this exhibit will be the SCPC + SCR plant versus the IGCC + SCR plant. This EPRI chart indicates that for bituminous coal the IGCC plants will produce:

- 67% less NO_x
- 93% less SO_2
- 40% less soot or fine particulate (PM10)

The potential for future electric cost increases due to future environmental regulations is less for IGCC because IGCC plants can control all emissions more economically than PC plants.

Q: **Do Other Recent Studies Show These Significant Differences in Emissions Between IGCC and PC Plants?**

A: Yes.

Exhibit RCF-11 summarizes an EPA Report, Environmental Footprints and Costs of Coal-Based Integrated Combine Cycle and Pulverized Coal Technologies, US. Environmental Protection Agency, EPA-430/R-06/006, July 2006. This EPA report compares the emission levels (in lb/MMBtu) that EPA believes should be obtained by current state-of-the-art IGCC and PC plants. This report also demonstrates the lower emissions that are capable with IGCC plants.

Q: **Do Recent IGCC Plants' Permit Levels and Proposed Permit Levels Confirm that these Significantly Lower Levels of Emissions can be Produced in Actual Plants?**

A. Yes.

Exhibit RCF-12 shows a summary of emissions from recent IGCC permits and proposed permit levels. This table summarizes proposed emission levels from IGCC plants that have recently received or applied for air permits. The IGCC plants proposed in the last 12 months have sought to control sulfur using Selexol, a more effective control strategy than MDEA. These plants include, AEP in Ohio and West Virginia, Northwest Energy, Tondu, Duke, ERORA (Illinois and Kentucky). Selexol effectively removes sulfur levels to between 0.0117 to 0.019 lb/MMBtu heat input into the gasifier.

As this table shows, a majority of IGCC plants that have filed applications in the last 12 months include selective catalytic reduction (SCR) to control NOx. These include, Northwest Energy, Tondu, ERORA in Illinois and Kentucky, and Duke in Indiana The Duke plant includes SCR, but bases reductions on diluent injection only. Since the preparation of this table the Taylorville plant now has a final permit and Cash Creek has a draft permit. The NO_x emission rates for SCR controlled IGCC plants is 0.012 - 0.025 lb/MMBtu based upon heat into the gasifier.

These trends toward Selexol and SCR adoption are occurring faster than EPA predicted in its July 2006 report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies. The July 2006 EPA report assumed that MDEA and diluent injection would be BACT for the near-term. This report was based upon a "snap shot" of IGCC permits that is out-of-date. As this table shows, the market has responded with technology faster than the EPA report anticipated.

In deciding which emission rates to compare to the AMPS-Ohio plant's proposed emission rates, the highest weight should be placed on recently proposed IGCC plants because they represent the most current view of IGCC permit levels. The least weight should be placed on existing IGCC plants and IGCC plants with permits issued prior to 2003 because they do not represent the capabilities of current IGCC technology.

Q. What are the Proposed Emission Rates from AMPS-Ohio Plant and How Do they Compare with Recent IGCC Permit Applications?

A. Exhibit RCF-13 summarizes the range of recently filed air permits for IGCC plants and compares them to the emission levels proposed in the draft air permit for the AMPS-Ohio plant. An IGCC plant would have significantly lower emissions of all pollutants than the proposed AMPS-Ohio.

Exhibit RCF-13 shows that:

An IGCC plant with the Selexol process would emit only 8% to 13% of the sulfur dioxide of the proposed AMPS-Ohio plant.

An IGCC plant with the SCR process would only emit 17% to 36% of the nitrogen oxides of the proposed AMPS-Ohio plant.

An IGCC plant would only emit 7% to 42% of the particulate mater of the proposed AMP-Ohio plant.

An IGCC plant would only emit 10% to 29% of the mercury of the proposed AMPS-Ohio plant.

An IGCC plant would also be expected to emit about three-quarters less CO and significantly less sulfuric acid mist and VOCs than the proposed AMPS-Ohio plant.

Q. What are the Total Tons per Year of Pollutant Emissions from the AMPS-Ohio Plant and How Do they Compare with Recent IGCC Permit Applications?

A. Exhibit RCF-14 is a comparison of the total tons per year of pollutants that the AMPS-Ohio plant (two 480 MW units = 960 MW) would emit under the Ohio EPA draft air permit and the emissions that a similarly sized IGCC plant (three 320 MW units = 960 MW) would emit, based on the final permit for the Taylorville IGCC plant in Illinois. This chart shows the significantly lower emissions of all pollutants for the Taylorville IGCC plant than the proposed AMPS-Ohio PC plant.

Exhibit RCF-14 shows that:

The Taylorville IGCC plant will only emit 35% of the nitrogen oxides of the proposed AMPS-Ohio plant.

The Taylorville IGCC plant will only emit 10% of the sulfur dioxide of the proposed AMPS-Ohio plant.

The Taylorville IGCC plant will only emit 54% of the particulate mater of the proposed AMP-Ohio plant.

The Taylorville IGCC plant will only be allowed to emit 66% of the mercury of the proposed AMPS-Ohio plant but the permit application filed for the Taylorville IGCC plant indicated that only 10% of the mercury of the proposed AMPS-Ohio plant would be emitted. The final permit also indicated that 95% mercury capture would be required.

The Taylorville IGCC plant will only emit 34% of the sulfuric acid mist of the proposed AMPS-Ohio plant.

The Taylorville IGCC plant will only emit 22% of the carbon monoxide of the proposed AMPS-Ohio plant.

The Taylorville IGCC plant will only emit 30% of the volatile organic compounds of the proposed AMPS-Ohio plant.

Q: What are the Proposed Emission Rates *from* AMPS-Ohio Plant and How Do they Compare with Recent PC Permit Applications?

A:

Exhibit RCF-15 compares the proposed permit emission rates of the AMPS-Ohio plant with two other recently proposed PC plants. These plants were selected for comparison because they will be utilizing the same types of coals and the same types of emission control systems as the AMPS-Ohio plant.

Exhibit RCF-15 shows that:

These proposed PC plants will only emit 71% of the nitrogen oxides of the proposed AMPS-Ohio plant.

These proposed PC plants will only emit 27% of the sulfur dioxide of the proposed AMPS-Ohio plant.

These proposed PC plants will only emit 87% of the particulate mater of the proposed AMP-Ohio plant.

These proposed PC plants will only emit 47% and 63% of the mercury of the proposed AMPS-Ohio plant.

VI. TAMPA ELECTRIC COMPANY (TECO) AND IGCC

Q. How Long have Commercial Size IGCC Plants been in Operation in the U.S.?

A. Commercial IGCC plants have been in operation for more than 10 years in the U.S.

Exhibit RCF-16 shows the Polk Power Plant near Tampa, FL which is a greenfield site and the Wabash Power Plant in Indiana which is a conversion of an existing plant.

Tampa Electric Company's (TECO) Polk Power Station began operation in 1996. It produces 250 MW (net) of electricity. It uses a Texaco (now GE) oxygen-blown gasification system. Power comes from a GE 107FA combined cycle system. During the summer peak power months, availability is greater than 90 percent when using back-up fuel.

The Wabash River Coal Gasification Repowering Project in Indiana began operation in November 1995. It demonstrated the repowering of an existing coal plant to IGCC. The plant uses an "E-Gas" oxygen-blown gasification system which is sold by ConocoPhillips.

For larger size plants, multiple units are being proposed which will improve system availability and reduce costs by making use of standard, modular designs.

Q. Have the Utilities Involved with these IGCC Plants Announced Plans to Build Other IGCC Plant?

A. Yes.

Tampa Electric Company had announced that they would build an additional 630 MW IGCC plant at the Polk Power Plant for operation in 2013. Tampa Electric started operation of its existing 315 MW(gross)/250MW(net) IGCC plant in October, 1996 and has recently celebrated its 10th year anniversary. It is the lowest cost plant to operate on Tampa Electric's System and has won numerous environmental awards.

Cinergy was the utility partner that was part of the Wabash IGCC plant. Cinergy has now merged with Duke Energy. Duke Energy has announced that they will build a 630 MW IGCC plant to be built at their Edwardsport Generating Station in Edwardsport, Indiana.

The Nuon Utility in the Netherlands, Belgium and Germany has been successfully operating an IGCC plant on coal and biomass for the past 12 years at about 253 MW. Nuon recently announced that they are building a 1200 MW plant which will consist of four 300 MW units.

There are 33 IGCC plants being planned in the United States by utilities and independent power producers. (Source: Tracking New Coal-Fired Power Plants, by DOE/NETL,October 10, 2007 page 13, www.netl.doe.gov/coal/refshelf/ncp.pdf)

Q: Has Tampa Electric Recently Deferred their New IGCC Plant?

A: Yes.. On October 4, 2007 Tampa Electric published a Press Release with the following statements:

"TAMPA ELECTRIC DEFERS USE OF CLEAN COAL GENERATING UNIT BEYOND 2013 NEEDS

Company cites financial risk to customers, shareholders from uncertain carbon requirements

Tampa, Florida – October 4, 2007 – Tampa Electric today announced that it no longer plans to meet its 2013 need for baseload generation through the use of integrated gasification combined cycle technology, or IGCC. Primary drivers of the decision announced today include continued uncertainty related to carbon dioxide (CO_2) regulations, particularly capture and sequestration issues, and the potential for related project cost increases. Because of the economic risk of these factors to customers and investors, the company believes it should not proceed with an IGCC project at this time.

The company remains steadfast in its support of IGCC as a critical component of future fuel diversity in Florida and the nation, and believes the technology is the most environmentally responsible way to utilize coal, an affordable, abundant and domestically produced fuel. Tampa Electric is recognized as the world leader in the production of electricity from IGCC. The company also believes that IGCC technology offers the best platform to capture and then sequester CO_2. Once public policy issues regarding long-term sequestration are resolved, demonstration projects can be conducted that will lead to a better understanding of the science, technologies and economics of sequestration."

Q: Has Nuon Recently Announced the Phased Construction of their New IGCC Plant?

A: Yes.

Nuon recently announced that due to significant construction cost increases for all major projects and the longer schedule for some major equipment they now have a two phase construction schedule to build the combined cycle part in phase 1 and the gasification part in phase 2.

Q: Are Tampa Electric and Nuon confident in the technical feasibility and significant environmental performance of IGCC plants?

A: Yes.

The announcements from Tampa Electric about their deferral and Nuon about their phased construction both indicated their confidence in the IGCC technology and its significant environmental performance. The primary reasons for Tampa Electric's decision are uncertainty related to carbon dioxide (CO_2) regulations, particularly capture and sequestration issues, and the potential for related project cost increases. The primary reasons for Nuon's decision is project cost increases and scheduling for some major equipment.

VII. REFERENCES TO CONTACT FOR PC AND IGCC PLANTS

Q. What Government Officials and Power Plant Managers are the Most Informed about the Advantages and Disadvantages of Using PC and IGCC Technologies for New Power Plants?

A. Exhibit RCF-17 shows references that I recommend to be contacted prior to anyone making a decision on which technology to use for a new power plant. Each of them have agreed to be contacted to provide their advise concerning their decision process in evaluating PC and IGCC plants.

VIII. COMMERCIALLY OPERATING AND PLANNED IGCC PLANTS

Q. Please Describe the Types and Number of Commercially Operating Gasification Plants.

A. Exhibit RCF-18 shows the results of the 2004 world survey of operating gasification plants prepared by the Gasification Technologies Council for the Department of Energy.

Gasification dates back to the 18th century, when "town gas" was produced using fairly simple coal-based gasification plants. But what we think of as modern gasification technology dates back to the 1930's when gasification was developed for chemicals and fuels production. Today (2007), there are around 130 gasification plants worldwide that produce fertilizers, fuels, steam, hydrogen and other chemicals, and electricity. Of these 130 plants, seventeen are IGCC plants.

Q. How Many Commercially Operating IGCC Plants Are There?

A. Exhibit RCF-19 shows seventeen (17) commercially operating IGCC plants. Together, these plants have a capacity of 3,872 MW(net) and have almost one million hours of operation on syngas. These plants use a variety of fuels including coal, petroleum coke, biomass, and refinery residues.

Four IGCC plants tend to be the focus of utility interest because they were designed to use coal: 1) Wabash, Indiana, 2) Polk, Florida, 3) Nuon, Netherlands, and 4) Elcogas, Spain. These four commercial IGCC plants have been operating from 10 to 13 years. They have successfully integrated the gasification process with the combined cycle power plant to enable more efficient use of coal while significantly reducing emissions. These plants range in size from 250 to 320 MW per unit.

A second set of plants built after Wabash, Polk, Nuon, and Elcogas are also important in the progression of IGCC. These plants operate at refineries in Italy. They are: Sarlux 545 MW, Sardinia; ISAB Energy 510 MW, Sicily; Api Energia 280 MW, Falconara; and Eni Power 250 MW, Ferrera. The first two demonstrate that IGCC plants can be built at a scale above 500 MW. Three of the plants were built using non-recourse project financing provided by over 60 banks and other lending institutions. They show that IGCC can be a commercially bankable technology.

Both the Salux and ISAB Energy plants use more than one gasification "train" and operate with more than 90 percent availability without a spare gasifier. The Italian experience with IGCC, while using refinery residues as fuel, is relevant to discussions of coal-fired or petcoke-fired IGCC, because essentially the same equipment is utilized in both instances, differing only in the feed preparation and how solids are removed.

The first commercial-scale demonstration IGCC plant in the United States was Southern California Edison's Cool Water Plant located at Barstow, California. It operated between 1984 and 1989. The plant successfully utilized a variety of coals, both subbituminous and bituminous, and had a feed of about 1,200 tons/day. The project used an oxygen-blown Texaco gasifier with full heat recovery using both radiant and convective syngas coolers.

Q. What is the Status of IGCC Projects and Gasification Projects being Developed in the North America?

A. Exhibits RCF-20, 21 and 22 show 57 of the publicly announced IGCC and gasification projects being developed in North America.

The range of IGCC projects under development in the United States includes proposals that would be fueled with petroleum coke, bituminous coal, subbituminous coal, and lignite.

A DOE Report lists 33 IGCC projects that are planned in the U.S. by utilities and independent power producers. This Department of Energy Report is Tracking New Coal-Fired Power Plants, by Eric Shuster, October 10, 2007, page 13 (Source: http://www.netl.doe.gov/coal/refshelf/ncp.pdf).

IGCC technology is commercially available from five major companies: GE, ConocoPhillips, Siemens, Shell and Mitsubishi Heavy Industries (MHI). The gasification industry has undergone many changes in the past few years that have given confidence to industry and lenders that IGCC can obtain sufficient performance warranties to build new IGCC plants. GE, a major company in the power field, has purchased ChevronTexaco's gasification business, and has partnered with Beohtel to offer fully warranted IGCC plants. ConocoPhillips has purchased the E-Gas technology from Global Energy. Siemens has purchased the German gasification technology formerly offered by Future Energy. Shell has partnered with Udhe and Black and Veatch.

Q. What is the Status of IGCC and Gasification Projects that are Presently Under Development Outside of North America?

A. Exhibits RCF-23 and 24 are a recent list that shows 26 of the IGCC and gasification projects that are being developed outside of North America.

IX. CARBON CAPTURE AND SEQUESTRATION (CCS)

Q: What is the Status of Proposed Power Plants with Carbon Capture & Sequestration?

A: Exhibit RCF-25 shows the proposed power projects above 275 MW that are being designed for CO2 capture and storage. The large majority of these projects will be using gasification and precombustion removal of CO2. This is due to the availability of proven commercial capture technology.

Q: Are Carbon Capture Technologies for PC Plants Commercially Available?

A: No.

Carbon capture technologies for PC plants are <u>not</u> commercially available. The MIT Report extrapolated the cost and performance for post-combustion capture of carbon dioxide from PC plants based on a very limited set of engineering data. Comparisons of this extrapolated data versus the commercial data that is available for CO2 capture from gasification plants obscures the fact that CO2 capture from PC plants are <u>not</u> close to commercial availability. Neither the amine or aqueous ammonia systems for CO2 capture at PC plants nor oxyfuel firing are close to commercial availability. Significant additional scale-up, improvements and testing are required for each of these technologies. The aqueous ammonia technology has been tested at the laboratory scale by DOE/NETL (Source: <u>Ammonia-based Process for Multicomponent Removal from Flue Gas"</u>, R&D Facts, DOE/NETL, September, 2007) and a 1 MW slipstream pilot plant is being planned. Oxyfuel combustion of pulverized coal is in its infancy, with the largest unit in operation a mere 1.5 MW (thermal) test facility in Alliance, Ohio (Source: <u>State of the Art</u>

of Oxy-Coal Combustion Technology for CO2 Control from Coal-Fired Boilers, by Farzan, H, et al, Babcock & Wilcox Technical Paper presented to Third International Conference on Clean Coal Technologies for Our Future, May 2007).

While these technologies should certainly be the subject of continued research, they are not likely to present real opportunities for carbon capture from coal use in the near term and should not be used at this time to justify the construction of new pulverized coal plants.

Other technologies for post-combustion capture of CO2 from PC plants have been discussed but at present those technologies remain speculative and appear to present significant environmental and/or economic challenges (e.g., chilled ammonia).

Q: Are Carbon Capture Technologies for IGCC Plants Commercially Available?

A: Yes.

Carbon capture technology for IGCC is commercially available and proven. In contrast to no commercial carbon capture technology for PC plants, IGCC plants carbon capture is considered a proven and commercially available technology. The necessary components of a carbon capture system for IGCC (water-gas shift reactors, acid gas removal systems, and CO2 compression) have been demonstrated at numerous facilities around the world, including the Great Plains Synfuels plant in North Dakota where 1 million tons of CO2 per year is captured from the gasification of lignite coal and used for EOR in Canada (Sources: The New Synfuels Energy Pioneers by Stan Stelter, Introduction by Former President Jimmy Carter, published by Dakota Gasification Co.- 2001, A subsidiary of Basin Electric Power Cooperative; and Experience Gasifying ND Lignite, by Al Lukes, Dakota Gasification Company, The Great Plains Synfuels Plant, presented at the Montana Energy Future Symposium).

While no existing IGCC plant captures carbon dioxide, industry confidence in the technology is very high. In recent testimony before the Florida Public Service Commission, Tampa Electric described the state of carbon capture equipment from IGCC in these terms: **"CO2 capture from syngas is a commercially proven process that has been used for decades around the world"** (Source:: Tampa Electric's Petition to Determine Need for Polk Power Plant Unit 6, Testimony of Mark J. Hornick, submitted to the Florida Public Service Commission on July 20, 2007).

X. SIZE AND AVAILABILITY OF NEW IGCC PLANTS

Q. Is it Possible to Build Large Size IGCC Plants?

A. Yes.

Large size plants are being built using modular designs that improve system reliability, increase efficiencies and provide fuel flexibility.

The Nuon Utility in the Netherlands, Belgium and Germany has been successfully operating an IGCC plant on coal and biomass for the past 12 years at about 253 MW. Nuon recently announced that they are building a 1200 MW plant which will consist of four 300 MW units. This design shown in Exhibit RCF-26 requires no additional scale-up from the design of their existing plant and makes use of readily available combined-cycle plants that have been used with natural gas. This modular design provides additional system reliability, increased efficiencies, fuel flexibility and any possible size.

The standard IGCC unit is now 300 MW. Most manufacturers are supplying 600 MW plants which consist of two 300 MW units. This is due to the fact that the gasifiers have been sized to produce the amount of synthesis gas needed for the 300 MW combined-cycle plants that are already in-service using natural gas. Therefore the 600 MW units that are being engineered consists of two units the same size as the existing units that have been operating for the past 10 years. Therefore there is no additional scale-up required. Any large size plant can be built by using additional 300 MW units. Three manufacturers have 300 MW IGCC units that have been operating successfully for the last 10 to 13 years. GE states that "IGCC technology can satisfy output requirements from 10 MW to more than 1500 MW, and can be applied in almost any new or repowering project where solid and heavy fuels are available." (Source: www.gepower.com/prod_serv/products/gas_turbines_cc/en/igcc/index)

Q. Have Recent Coal Gasification Plants and IGCC Plants Demonstrated Reliabilities Above 90% Required by the Utility Industry?

A. Yes.

A recent Gas Turbine World article reported on the capacity factors of the more recently built IGCC plants in Italy that utilize refinery waste such as asphalt as a fuel. As the report notes, the availability of these plants are between 90% and 94%. (Source: Refinery IGCC plants are exceeding 90% capacity factor after 3 years, by Harry Jaeger, Gas Turbine World, January-February 2006.)

Now GE offers to take on responsibility for everything "From Coal off the Coal Pile to Electrons on the Grid" by Ed Lowe, GE General Manager of Gasification (Source: Inside Business, Time Magazine, November, 2006.)

An additional advantage of an IGCC plant is that it can operate on various fuels. If the gasifier is out-of service for maintenance the power plant can still operate on natural gas or diesel fuel. This is not possible with a PC plant which is only designed for coal. Older IGCC plants built in the early 1990s such as Polk and Wabash that operate without a spare gasifier have demonstrated availabilities above 85%.

Major vendors of IGCC plants such as GE, Shell and ConocoPhillips will warrant that new IGCC plants will achieve greater than 90% availability with a spare gasifier. The economic comparisons conducted for Tampa Electric's IGCC plant indicate that it is more cost effective to operate on natural gas or diesel fuel than to build a spare gasifier to increase plant availability. Tampa Electric's IGCC plant has demonstrated reliability to produce electricity of 95% with their dual fuel capability. This is greater than PC plants that do not have dual fuel capability. (Source: Tampa Electric's Presentation of Operating Results, by Mark Hornick, Plant Manager, presented during plant tours.)

Therefore IGCC plants are being built without a spare gasifier. They will be able to operate above 90% availability by using their back-up fuel of either natural gas or diesel.

Reliability and availability are measures of the time a plant is capable of producing electricity. Reliability takes into account the amount of time when a plant is not capable of producing electricity because of unplanned outages. Availability takes into account the time when a plant is not capable of producing electricity because of planned and unplanned outages.

XI. THE GREAT PLAINS SYNFUELS PLANT

Q. Are There Any Commercially Operating Gasification Plants That Are Capturing CO_2?

A. Yes.

Exhibit RCF-27 shows the Great Plains Synfuels Plant in Beulah, North Dakota which is a good example of a commercial gasification plant. It began operating in 1984 and today produces more than 54 billion cubic feet of Synthetic Natural Gas (SNG) from 6 million tons of coal per year. If the SNG from this one plant were used in combined-cycle power plants there would be enough fuel for more than 1,000MW of generating capacity.

Adjacent to the Great Plains Synfuels Plant is the Antelope Valley Station which consists of two 440 MW lignite coal power plants that also started operation on lignite in the early 1980s.

Both plants are owned by the Basin Electric Power Cooperative. Al Lukes, Senior Vice President and COO of the Dakota Gasification Company, presented a paper at the 2005 Gasification Technologies Conference entitled Experience with Gasifying Low Rank Coals which showed the significantly lower emissions from the coal gasification plant than the coal-fired power plant. I recently asked Al Lukes which technology he would select today for a power plant, and he said "definitely the gasification technology".

Q. Has the Great Plains Synfuels Plant been Able to Commercially Demonstrate that the CO_2 from this Coal Gasification Plant can be Economically Captured and Injected?

A. Yes.

Carbon dioxide capture, transportation and injection has been operating commercially since 2000 at the Great Plains Synfuels Plant. In 2000, the Great Plains Synfuels Plant added a CO_2 recovery process to capture the CO_2. It transports the CO_2 by pipeline 205 miles, as shown in Exhibit RCF-28, to the Weyburn oil fields where it is used for enhanced oil recovery (EOR). In this way, the CO_2 does not become a global warming emission source but is sold as a useful byproduct to recover additional oil from depleted oil fields. Monitoring of the injected CO_2 has shown that this injection is effectively containing the CO_2 underground, although there are not specific standards in place addressing criteria for long-term sequestration. This CO_2 recovery process is expected to help extract 130 million extra barrels of oil from this oil field. This demonstrates the ability to efficiently capture and inject the CO2 from the gasification process.

XII. WATER CONSUMPTION FOR PC AND IGCC PLANTS

Q. Do IGCC Plants Use Less Water than PC Plant?

A. Yes.

Exhibit RCF-29 shows that an IGCC plant without carbon capture & sequestration (w/o CCS) uses 4,003 gpm of raw water versus the proposed sub-critical PC plant design proposed for AMPS-Ohio plant which will consume 6,212 gpm. This DOE/NETL Report shows that the proposed design for the AMPS-Ohio plants will consume 55% more water than the same size IGCC plant.

Exhibit RCF-29 also shows that an IGCC plant with carbon capture & sequestration (w/ CCS) uses 4,579 gpm of raw water versus the proposed sub-critical PC plant design proposed for AMPS-Ohio plant which will consume 14,098 gpm. This DOE/NETL Report shows that the proposed design for the

AMPS-Ohio plants will consume 200% more water than the same size IGCC plant. These are significant additional financial and environmental risks caused by the the proposed PC plants.

After considering the available technologies and the nature and economics of the various alternatives, the proposed AMPS-Ohio PC plants do not incorporate the maximum feasible water conservation practices.

The lower water usage for an IGCC plant w/o CCS is due mostly to the fact that a combined cycle power plant is being used which requires less cooling tower water. A combined cycle power plant consists of both a gas turbine and a steam turbine for power generation. The gas turbine portion of the power generation cycle does not require the large quantities of water for cooling that are needed for the steam turbine cycle. Since a PC plant generates all of its electricity from the steam turbine cycle it requires larger amounts of water.

Combined cycle plants are more energy efficient but require a clean fuel such as natural gas, diesel, or synthesis gas. The older, less efficient technology uses only a steam turbine, which must be used for PC plants due to the contaminants in the combustion products.

XIII. THE BENEFITS OF FUEL FLEXIBILIY FOR POWER PLANTS

Q: What are the Benefits of a Power Plant being Able to Use Different Fuels?

A: The 1200 MW IGCC Plant to be built by the Nuon Utility in The Netherlands is a good example of a multi-fuel power plant. This plant is shown in Exhibit RCF-26. It will have the capability of using coal, petcoke, biomass and natural gas. This plant will be able to respond to changing fuel prices and availability of these alternative fuels. The coal, petcoke and biomass can all be gasified to produce syngas for the combined-cycle power plants.

The biomass capability enables IGCC plants to use various renewable energy sources that will reduce the emissions of CO_2. Initially available biomass can be used as a lower cost fuel and then renewable energy crops can be developed as a new industry.

Adisadvantage of PC plants is that they are only capable of using coal. Therefore PC plants can not respond to changing market conditions and changing emission standards without significant increases in costs.

XIV. POWER PLANT EFFICIENCY

Q: What is the Heat Rate and the Efficiency of the Proposed AMPGS?

A: Neither the heat rate nor the efficiency of the proposed AMPGS are provided but can be calculated from the fuel input (5,191 million Btu per hour) provided on page 216 of the Draft Permit and from the electrical output (480 MW per unit) provided on page 1 of the Application for Need. From these two numbers the calculated heat rate and efficiency for the AMPGS are:

Heat Rate = 10,814 Btu per Kwh

Efficiency = 31.56 %

Although it is not stated in the Application for Need or the Draft Permit, it can be assumed from this heat rate and efficiency that the AMPGS will be using a sub-critical PC plant design.

Q: How Does the Heat Rate and Efficiency of the AMPGS Compare with Other PC Plant Designs?

A: Exhibit RCF-30 shows the various PC plant designs including sub-critical, super-critical and ultra-supercritical. These classifications are based upon the steam conditions that can be produced in these PC plants. The higher the temperature and pressure of steam that can be produced then the higher the efficiency of the plant. Higher efficiency plants will require less fuel and have a lower heat rate. The amount of fuel used is directly proportional to its heat rate and inversely proportional to its efficiency . Therefore a 38% efficient super-critical PC plant will use **20% less fuel** than a 31.56% efficient sub-critical PC plant.

The higher efficiency and lower heat rate is very important for two reasons. The less fuel used the lower the cost of electricity and the lower the emissions per Kwh of electricity produced. The current emission regulations are based upon pounds of pollutants emitted per Btu of heat input into the boiler. Therefore appropriate credit is not currently given for the higher efficiency of some power plant designs. EPA is in the process of changing their regulations from being based upon a heat input basis to being based upon an electricity output basis. This will then give appropriate credit to power plants with improved efficiencies.

Q: Have Other Studies Recognized the Importance of Power Plant Efficiencies?

A: Yes.

The Executive Summary from The Future of Coal, by the Massachusetts Institute of Technology (MIT), April 2007, page xiv, states: **"recommending that new coal units should be built with the highest efficiency that is economically justifiable"**

Q: Does the Higher Capital Cost of the Super-critical PC Plants Increase the Cost of Electricity by More than its Fuel Cost Savings?

A: No.

Both the M.I.T. Report and the DOE/NETL Study show that the Cost of Electricity (COE) is less for the Super-critical PC plant than the Sub-critical PC plant.

This proves that for PC plants the higher efficiency can be economically justified. Therefore AMPGS should not be specifying low efficiency PC plants since this will increase the costs of electricity and increase the emissions.

Q: Are the Higher Efficiency Super-critical Plants as Reliable as the Lower Efficiency Sub-critical Plants?

A: Yes.

Exhibit RCF-31 shows that the reliability is comparable for sub-critical and super-critical PC plants. This comparison is for a significant number of units within the same size range and from comparable ages of plants.

Q: Are Super-critical PC Plants Being Constructed by Most of the Major Equipment Manufacturers?

A: Yes.

Exhibit RCF-32 lists the various original equipment manufacturers and a sample of some of the super-critical plants that they have provided with the steam conditions for these plants.

Exhibit RCF-1

Richard C. Furman Resume

RICHARD C. FURMAN
CONSULTING ENGINEER

Address: 10404 S.W. 128 Terrace, Miami, Florida 33176
Date of Birth: January 7, 1947
Height: 6'0" **Weight: 170 lbs.**
Marital Status: Married: 2 children
Phone #: (305) 232-4074 office; (305)439-5604 cell
E-mail: RcFurman2@aol.com

Education: Massachusetts Institute of Technology, MS CHE 1972.
Worcester Polytechnic Institute, BS CHE 1969.

Experience:

February 2003 to Present

Retired – Volunteer at Camp Sunshine to help children with cancer and volunteer for the Clean Air Task Force (CATF), the Natural Resources Defense Council (NRDC), Environmental Defense, Sierra Club and Public Citizen to advise utilities, government agencies and the public about the environmental benefits, economic potential and energy security of using coal gasification technologies to produce electricity, fuels and chemicals.
Provided expert testimony and information on new energy technologies to Florida's Public Service Commission, Texas Senate Committee on Natural Resources and Georgia's Public Service Commission.

September 1989 - February 2003

Consulting Engineer – New Energy Technologies

Consulting engineer to various utility companies, equipment manufacturers, government agencies and environmental organizations on the development and application of new energy technologies.
Consultant in the areas of coal gasification, integrated gasification combined-cycle (IGCC) power plants, alternative fuels, cogeneration and natural gas cooling technologies.
Identify potential applications for these new technologies with electric and gas utilities. Introduce these new technologies to company executives, government officials and potential users. Assist engineers with designs and applications for these new technologies. Create marketing programs with manufacturers for increased use of these technologies.
Direct technical feasibility studies and financial analyses for site specific applications. Assist equipment manufacturers, the Electric Power Research Institute (EPRI), the Gas Research Institute (GRI), and the American Gas Cooling Center (AGCC) with development and demonstration of these new technologies.
Provided expert testimony and information on new energy technologies to Brazil's Center for Gas Technology and Trinidad's National Gas Company.

August 1981 - August 1989

Consulting Engineer – New Fuel Technologies

Consultant to various companies on the technical feasibility and business development for new fuel technologies. Major areas of consulting consist of the development and use of alternative new fuels and the conversion of power plants to these new fuels. Director and project manager for various development programs, feasibility studies, financial analyses, R&D projects, marketing analyses and commercialization of these new fuel technologies.

April 1977 - July 1981

Florida Power & Light Company, Miami, Florida
Senior Project Coordinator – Research and Development
Managed FPL's coal conversion program and fuels R&D program. Developed R&D projects with emphasis on alternative fuels and processes for electric power generation. Assessed the technical and economic feasibility of coal gasification, advanced coal cleaning technologies, coal-oil mixture technologies, coal-water slurry technologies, coal liquefaction processes, fluidized combustion processes and advanced pollution control methods. Established company R&D projects in uranium recovery, coal cleaning, coal-oil mixtures, coal-water slurries and combustion modifications.

September 1975 - March 1977

Center for Energy Policy, Inc., Boston, Massachusetts
Program Manager

Organized multi-disciplinary studies on the technical and economic feasibility of power plant conversions from oil to coal, the pricing policies for fuels and electricity and future methods for energy conservation in space heating. Directed engineering study for the conversion of New England Electric's Brayton Point Plant from oil to coal.

May 1972 - September 1975

Walden Research Division of ABCOR, Inc. Cambridge, Mass.
Senior Engineer

Industrial consultant for air pollution control, energy conservation, and industrial hygiene. Engaged in process modifications to reduce energy consumption. Responsible for engineering evaluations of air pollution control systems.

September 1970 - June 1972

Massachusetts Institute of Technology, Cambridge, Mass.
Graduate Student, Teaching Assistant, Researcher

Researcher – NSF grant to evaluate future energy sources and their environmental impact. Researcher for book entitled "New Energy Technology," by Hottel and Howard, MIT Press.

Graduate Student – Master's thesis: "Technical and Economic Evaluation of Coal Gasification Processes."

Teaching Assistant – "Principles of Combustion and Air Pollution" and "Seminar in Air Pollution."

June 1969 - February 1970

Southern California Edison Company, Los Angeles, California
Chemical Engineer
Engaged in power plant combustion air pollution control. Investigated two-stage combustion to reduce nitrogen oxides emission.

Professional Organizations

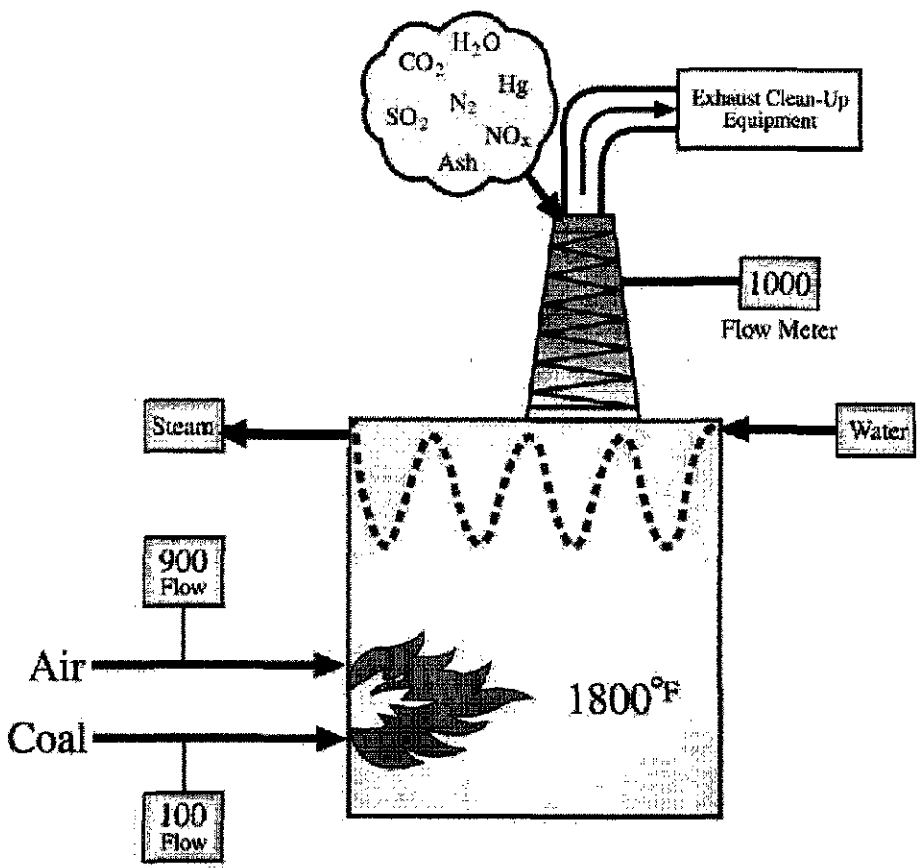
Electric Power Research Institute - EPRI
Gas Research Institute - GRI
Association of Energy Engineers - AEE
Cogeneration Institute - CI
American Institute of Chemical Engineers – AIChE
American Gas Cooling Center – AGCC

Exhibit RCF-2

COMBUSTION VERSUS GASIFICATION

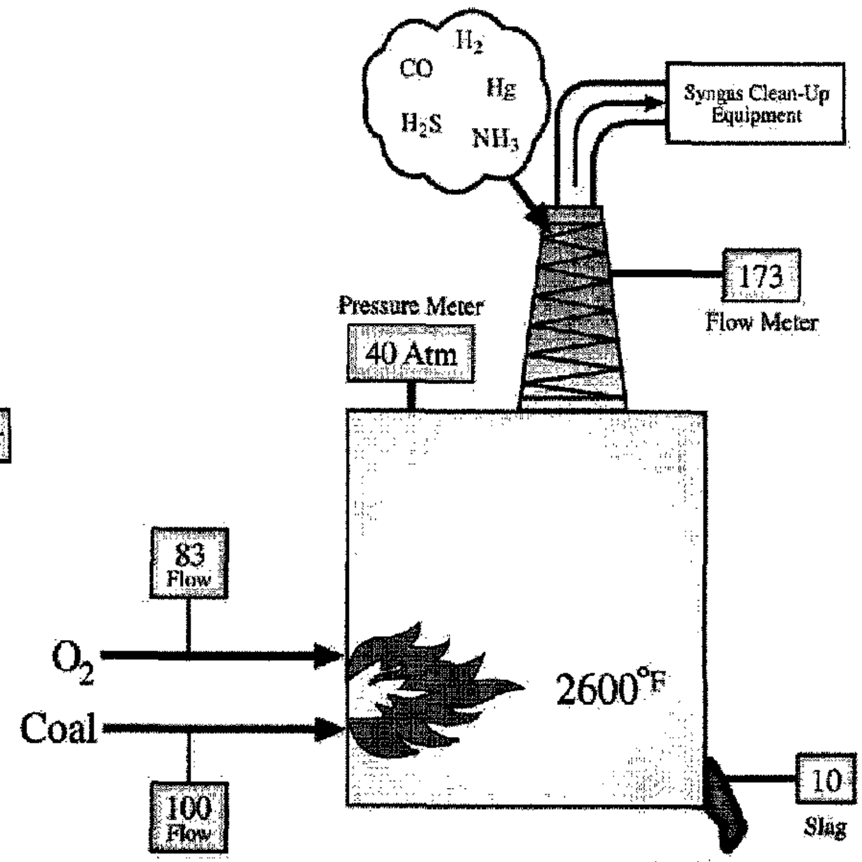
Volume of Exhaust Gas Clean-Up | **Volume of Syngas Clean-Up**

160 X



Coal Boiler

X



High Pressure Coal Gasifier
with Oxygen

- (Source: EPRI Presentation – "Gasification Combined Cycles 101" by Dr. Jeffrey Phillips, pages 9 and 12, presented at the Workshop on Gasification Technologies, Tampa, FL 3/2/06)

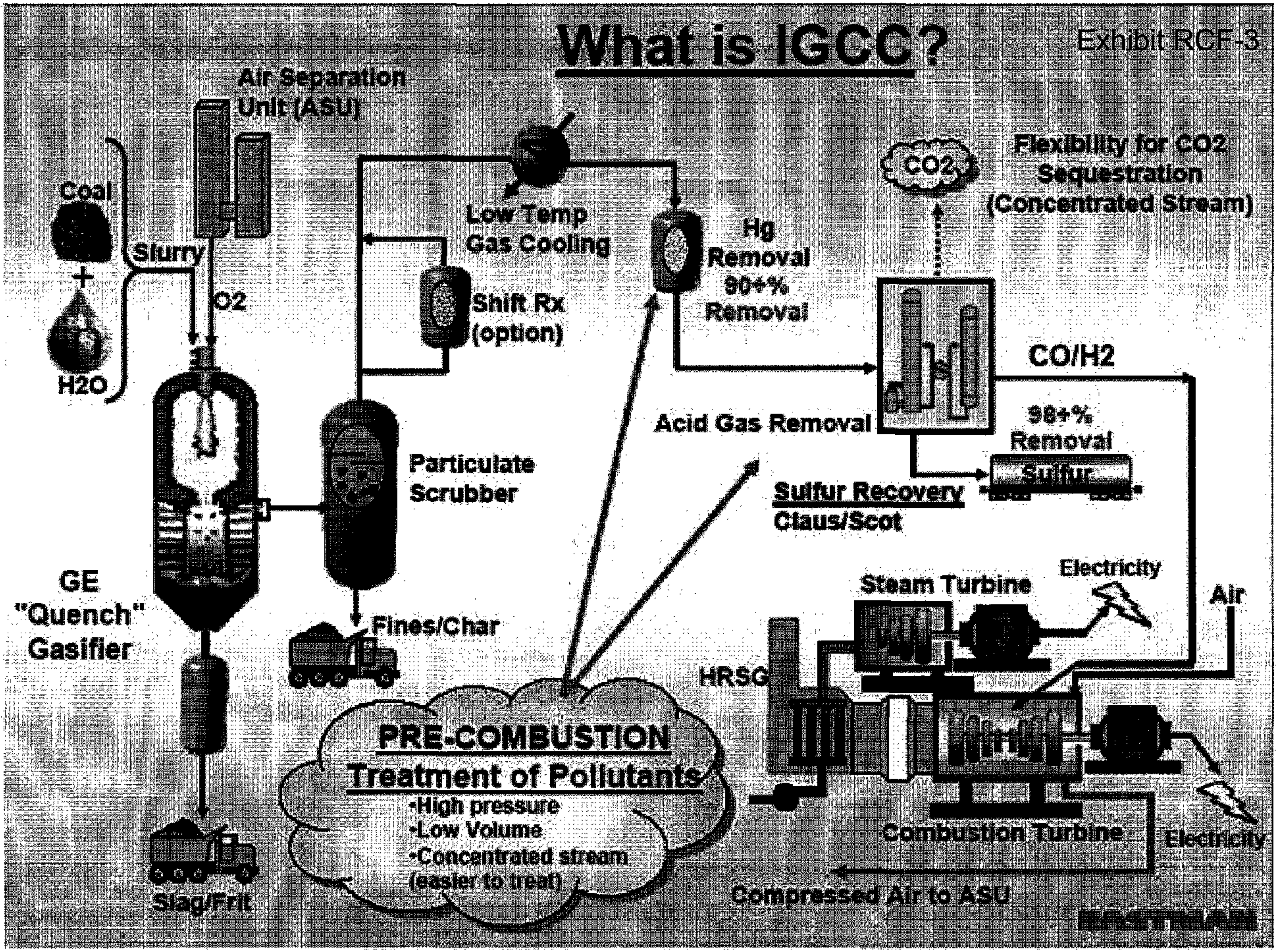
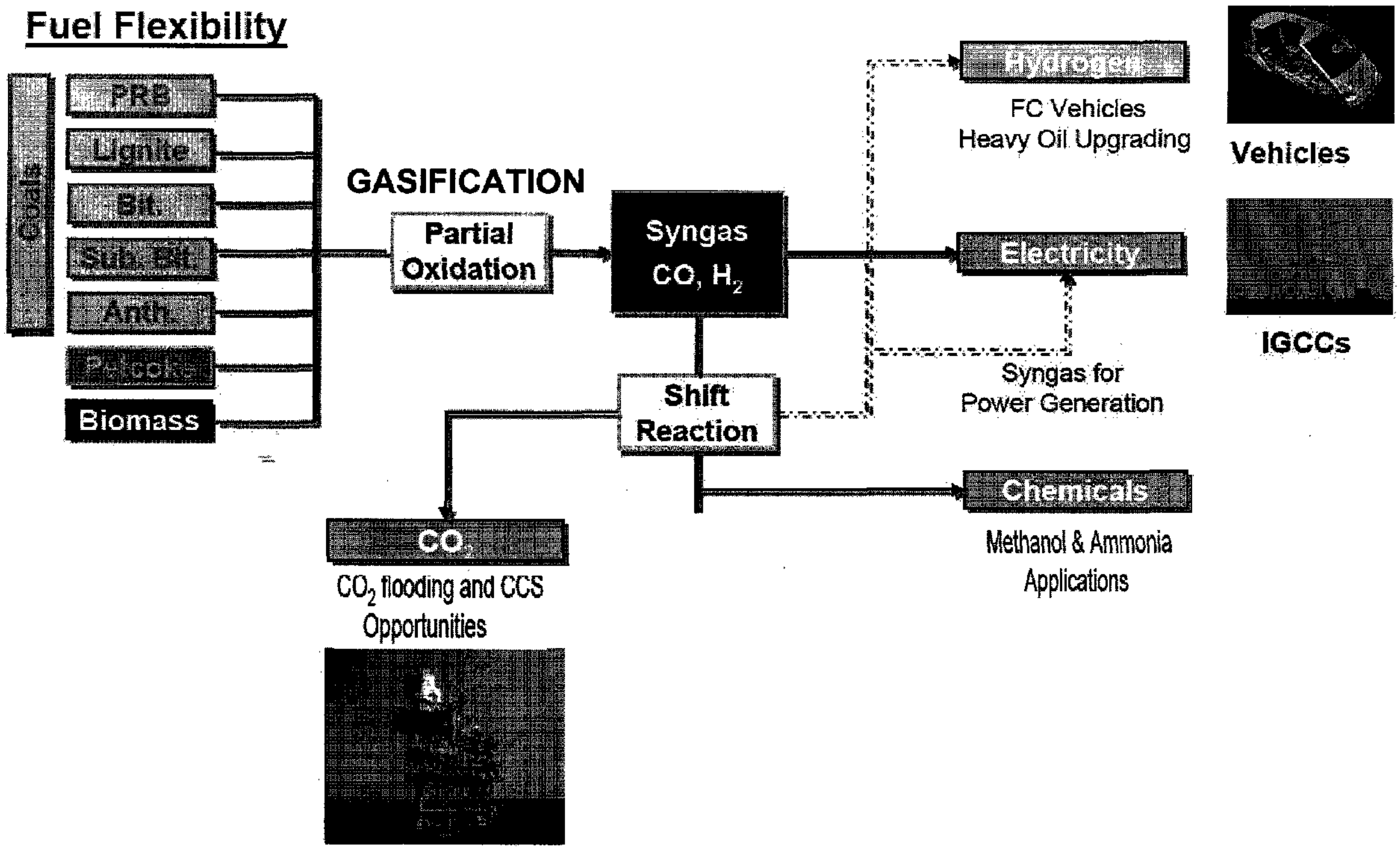

What is IGCC?
Exhibit RCF-3
Air Separation Unit (ASU)
Coal
H2O
Slurry
O2
Low Temp Gas Cooling
Shift Rx (option)
Particulate Scrubber
Hg Removal 90+% Removal
Flexibility for CO2 Sequestration (Concentrated Stream)
CO2
CO/H2
Acid Gas Removal
98+% Removal
Sulfur
Sulfur Recovery
Claus/Scot
GE "Quench" Gasifier
Fines/Char
Slag/Frit
PRE-COMBUSTION
Treatment of Pollutants
•High pressure
•Low Volume
•Concentrated stream (easier to treat)
HRSG
Steam Turbine
Electricity
Air
Combustion Turbine
Electricity
Compressed Air to ASU

Exhibit RCF-4

GASIFICATION – Wide Range of Fuels and Products



•Source: "Shell Coal Gasification in North America", by Milton Hernandez, Shell U.S. Gas & Power, presented at GTC, Oct. 2, 2006

Exhibit RCF-5

Table 3.7 Relative Cost of Electricity from PC and IGCC Units, without and with CO_2 Capture*

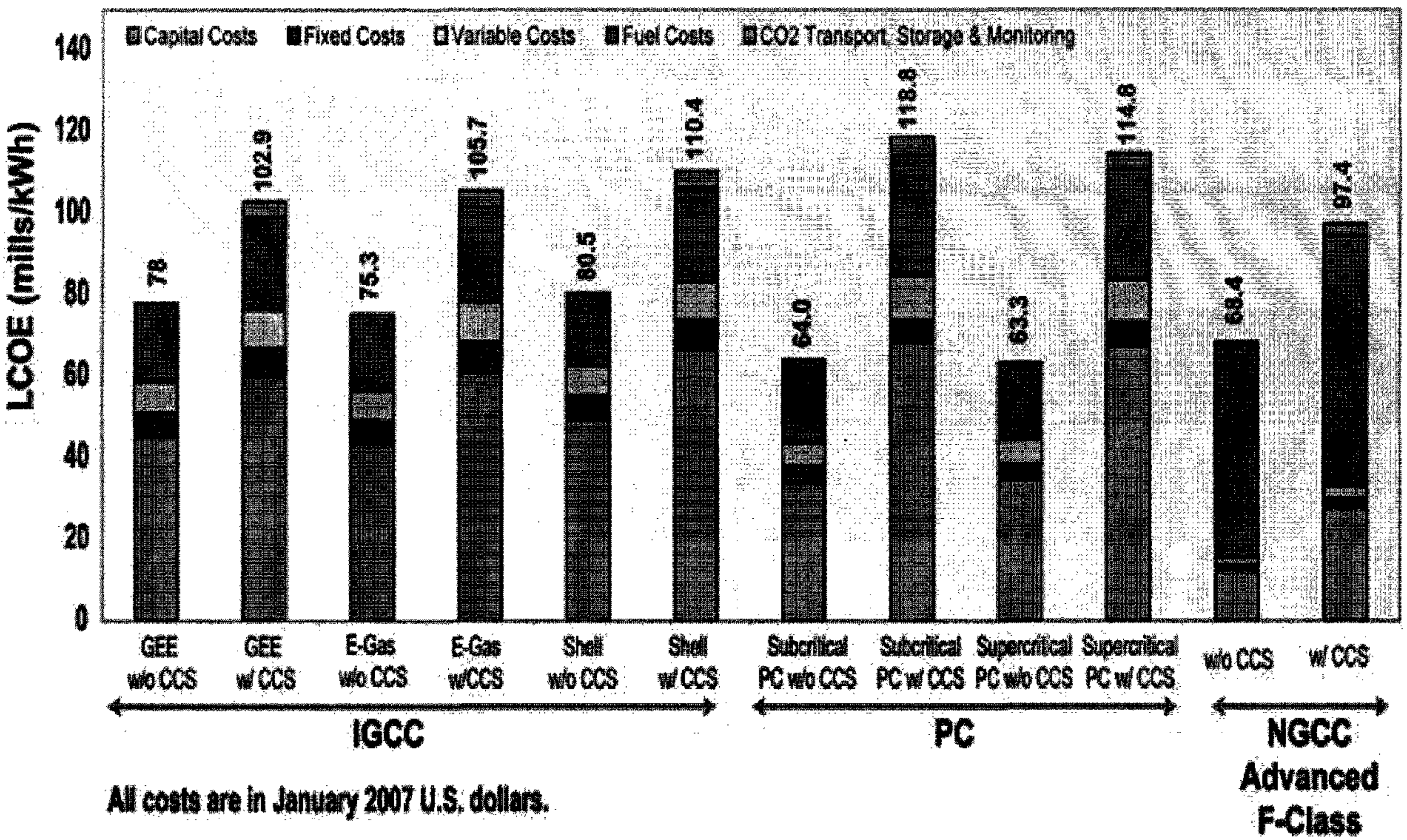
	MIT	GTC	AEP	GE
PC no-capture, reference	1.0	1.0	1.0	1.0
IGCC no-capture	1.05	1.11	1.08	1.06
IGCC capture	1.35	1.39	1.52	1.33
PC capture	1.60	1.69	1.84	1.58

*Included are: the MIT Coal Study results (MIT), the Gasification Technology Council (GTC) [56], General Electric (GE) [57], and American Electric Power (AEP) [58].

Source: "The Future of Coal" by the Massachusetts Institute of Technology (MIT), April 2007, page 36.

Exhibit RCF-6

Figure 7. Levelized Cost-of-Electricity



Source: "Fossil Energy Power Plant Desk Reference", DOE/NETL-2007/1282, May 2007, Overview-6, Figure 7.

Table III-2, Example Calculation of True Economic Impact of IGCC and SCPC[46]

Facility Parameter	**IGCC**	**SCPC**
Output, Gross, MW	575.00	541.00
Output, Net, MW	500.00	500.00
Cost of Electricity Generation, $/MWh, net	**68.20**	**58.94**
PM (Filterable), lb/MWh (gross)	0.052	0.100
SO2, lb/MWh (gross)	0.089	0.541
NOx, lb/MWh (gross)	0.375	0.494
PM Damages at $17.00/kg, $/MWh (gross)	1.95	3.75
SO2 Damages at $10.44/kg, $/MWh (gross)	2.05	12.45
NOx Damages at $16.00/kg, $/MWh (gross)	13.23	17.43
Total of Above Damages, $/MWh (net)	**19.81**	**36.39**
Total Costs, $/MWh, net	**88.01**	**95.33**

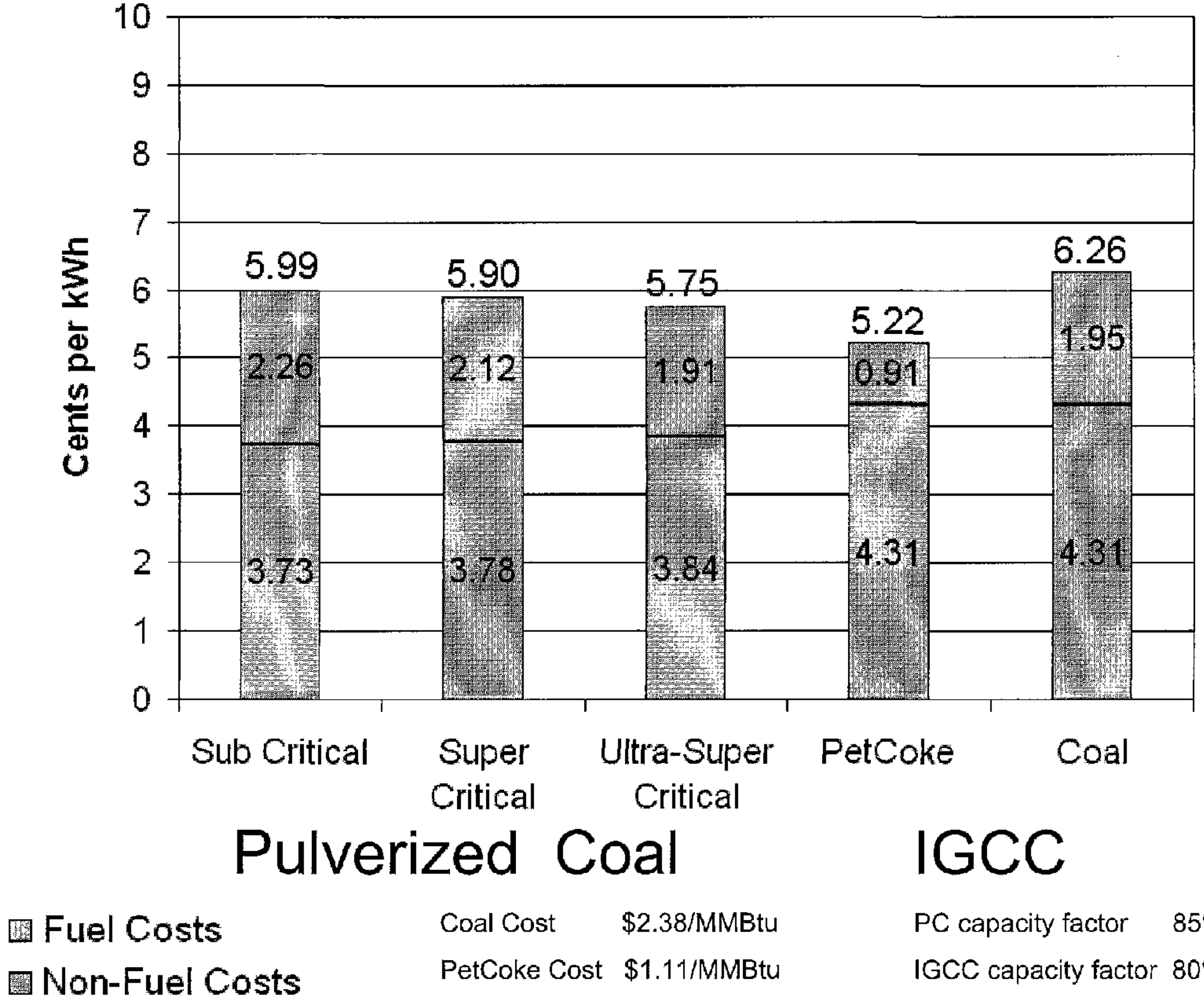
[46] All values based on EPA Footprints Report estimates for sub-bituminous coal units. 85% capacity factor, 17.5% capital recovery factor, and $1.80/MMBtu delivered coal price assumed for both technologies. Emissions rates and costs for IGCC do not include SCR.

Median costs used for environmental and health damages as provided from published studies – see "World Energy Assessment", by United Nations Development Programme, 2000, Table 8.1

Source: Clean Air Task Force (CATF) comments dated September 28, 2007 to the Michigan Department of Environmental Quality on their July 26, 2007 Fact Sheet: Environmental Permitting of Coal-Fired Power Plants in Michigan

Exhibit RCF-8

Cost of Electricity Comparison Chart for Florida

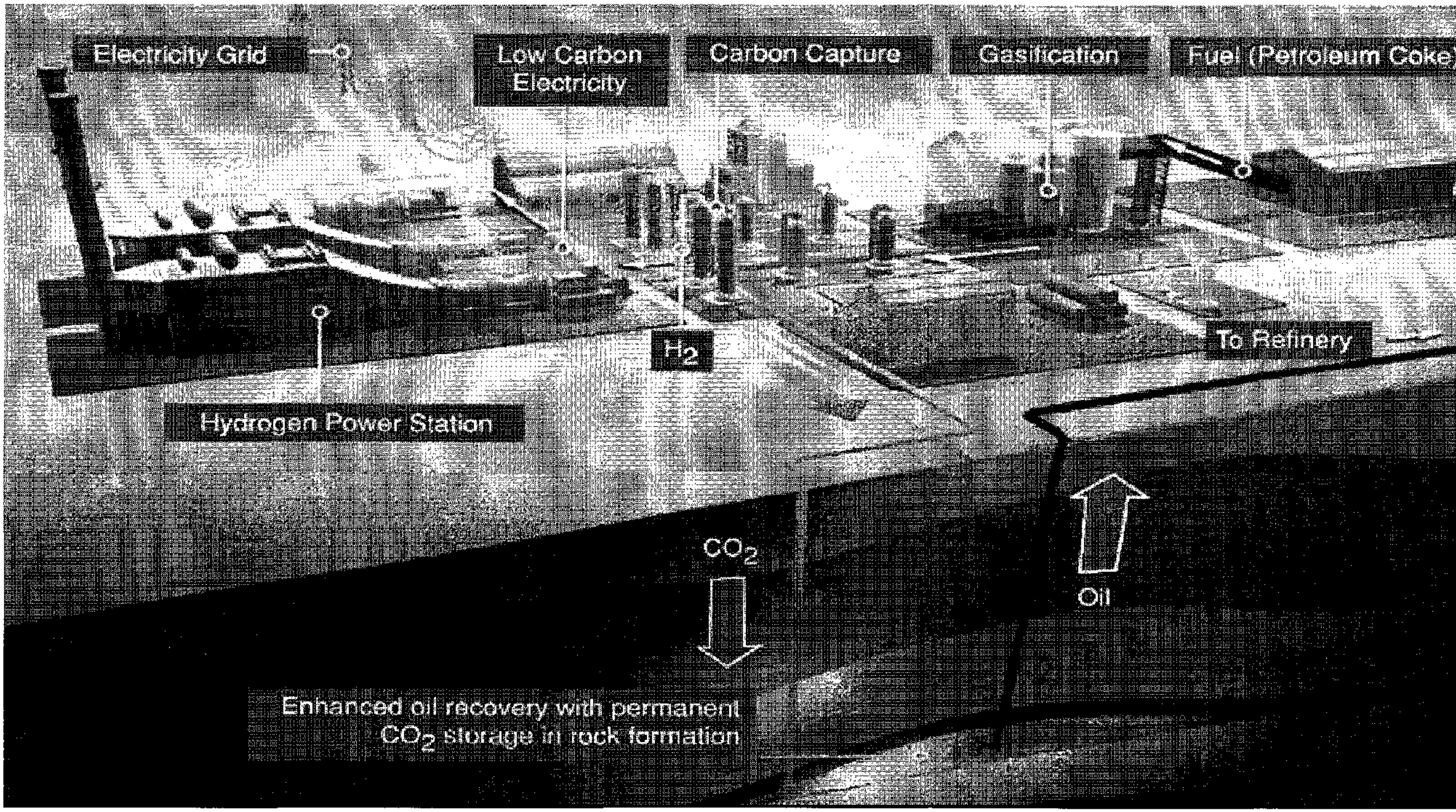


Coal Cost	$2.38/MMBtu	PC capacity factor	85%
PetCoke Cost	$1.11/MMBtu	IGCC capacity factor	80%

rcfurman2@aol.com

Exhibit RCF-9

Proposed 500 MW IGCC Plant Using Petcoke with CO2 Capture and Enhanced Oil Recovery at the BP Carson Refinery

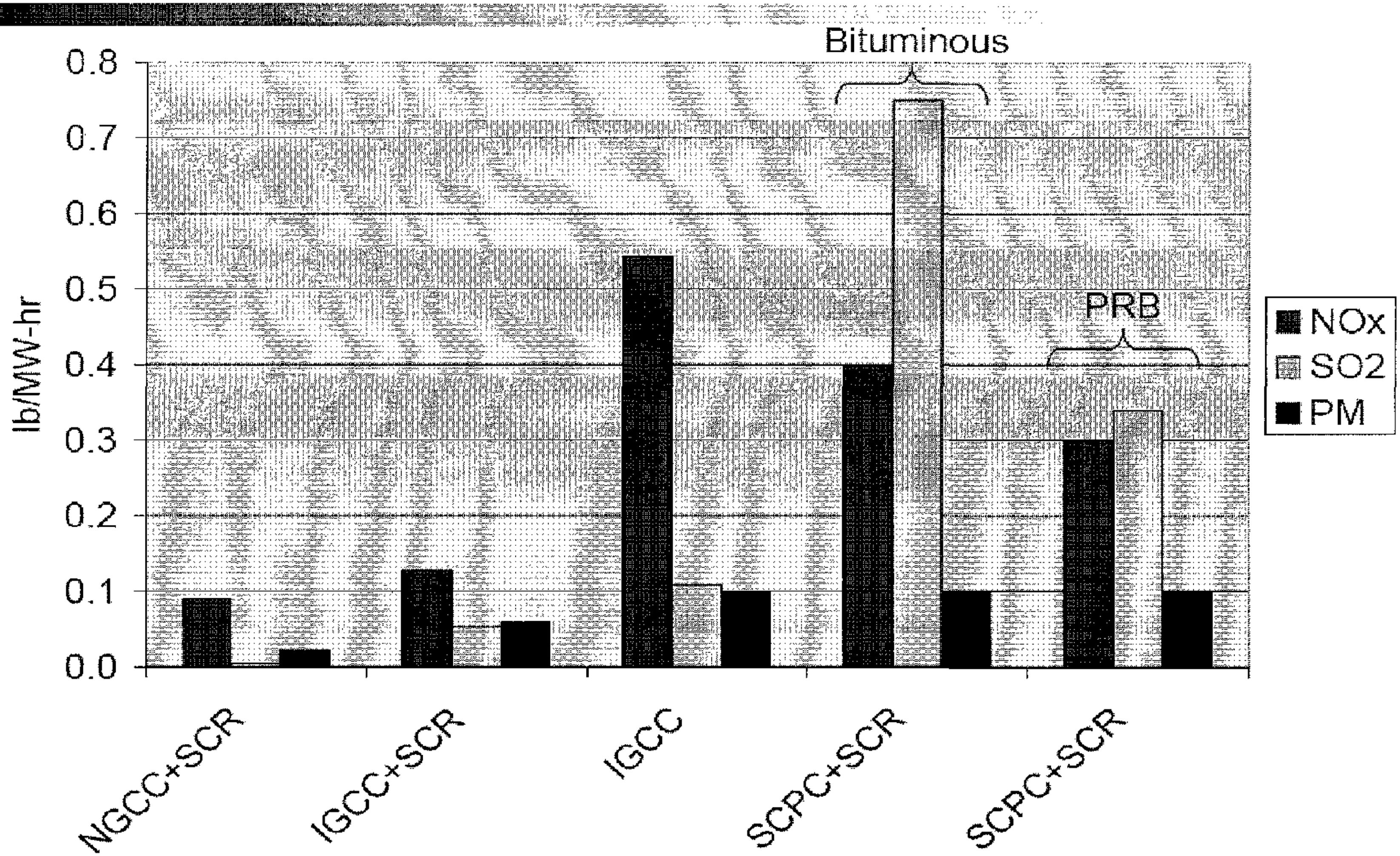


Source: "Outlook for coal-based IGCC power generation", Gas Turbine World, January – February 2007, p. 25.

Exhibit RCF-10

Emissions Comparison – State-of-the-Art Coal Combustion, IGCC, and NGCC

Values represent technology capability, not permit levels



Source: "Gasification 101", by Jeffrey Phillips, Electric Power Research Institute (EPRI), presented at Gasification Technologies Workshop in Bismarck, ND June 28-29, 2006, page 27.

Exhibit RCF-11

IGCC and Pulverized Coal (PC) Air Emissions Comparisons

Parameter	Bituminous Coal			
	IGCC Slurry Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC
NO_x (as NO_2)[1] (lb/MMBtu)	0.043	0.056	0.056	0.055
SO_2 [2] (lb/MMBtu)	0.038	0.080	0.080	0.079
PM [3] (lb/MMBtu)	0.006	0.011	0.011	0.011
Mercury [4] (lb/yr)	24.1	29.3	27.4	24.5

Source: Environmental Footprints and Costs of Coal-Based Integrated Combine Cycle and Pulverized Coal Technologies, U.S. Environmental Protection Agency, EPA-430/R-06/006, July 2006.

Note: Lb/MMBtu and lb/yr values calculated from EPA's lb/MWH and heat rate data.

1 The NO_X emission comparisons are based on emission levels expressed in ppmvd at 15% oxygen for IGCC and lb/MMBtu for PC.

2 SO_2 removal efficiency basis is 98% for PC. Removal efficiency basis for IGCC is 99%.

3 Particulate removal is 99.9% or greater for the IGCC, 99.8% for bituminous coal and 99.7% for sub-bituminous.

4 Mercury emission rates are based on the premise that mercury-specific controls are installed and operate at 90% efficiency.

Source: Testimony of Paul Carpinone, Tampa Electric Company, to Florida Public Service Commission, July 20, 2007, p 14, for Tampa Electric's Petition to Determine Need for Polk Power Plant Unit 6.

Exhibit RCF-12

SUMMARY OF RECENT IGCC PERMITS AND PROPOSED PERMIT LEVELS

	Approved Permit					Application Filed, Draft Permit Not Issued Yet						
Pollutant	Global Energ Lima, Oh, 59 MW	Kentucky Pionee Energy, KY	Wisconsin Electric Elm R 600 MW	ERORA Cash Cre KY, 630 MW	Southern Illinoi Clean Energy Complex, IL, 64 MW & 110 MMS methane	ERORA, Taylorville, IL MW	Nueces, T 600 MW	Energy Northwest WA, 600 MW	AEP, OH, 629 MW	AEP, WV, 629 MW	Mesaba One (606 MW), Mesaba Two (606), MN,Total 1,2 MW	Duke, Edwardsp t, IN, 630 MW
	(in lb/MMB	(in lb/MMBtu)	(in lb/MMBtu)	(in lb/MMBtu)	(in lb/MMBtu)	(in lb/MMBtu)	(lb/MMBtu	(lb/MMBtu	(lb/MMBtu	(lb/MMBtu	(lb/MMBtu)	(lb/MMBtu
SO2	0.021	0.032 -3 hr ave	0.03 -24 hr ave	0.0117 -3 hr ave	0.033 -30 day ave	0.0117 -3 hr ave	0.019	0.016 -3 hr ave	0.017	0.017	0.027	Repower, n from BACT
NOx	0.097	0.0735 -3 hr ave	0.07 (15 ppmdv) -30 day a	0.0246-24 hr ave	0.059 -30 day ave	0.0246 -24 hr ave	0.019	0.012 -3 hr ave	0.057	0.057	0.057	Repower, n from BACT
Mercury			.56 x 10-6	.197 x10-6 (1)	.547 X10-6	.19 x 10-6 (1)	1.825 x10-6	1.1 x10-5			90% removal, .026 tons Phas I and II total	.008 tons/y
PM	0.01	.0.011	0.011 (backhalf)				0.015	0.001			0.009	18.1 lbs/hr
PM10			0.011 (backhalf)	0.0063 -3 hr ave (filterable)	0.00924 (filterable)	0.0063 -3 hr ave (filterable)	0.014		.006 (filterable)	.006 (filterable)		
VOC	0.0082	0.0044	0.0017 -24 hr ave (LAER) (3)	0.006 -24 hr ave	0.0029	0.006 -24 hr ave	0.004	0.00	0.001	0.001	0.0032	1.4 ppmvw
Sulfuric Acid Mist			0.0005 -3 hr ave	0.0026 -3 hr ave	0.0042 -30 day ave	0.0026 -3hr ave	0.0001		98 tons/yr	98 tons/yr		
Fluorides (2)												
CO	0.137	0.032 -3 hr ave	.030 -24 hr ave	0.036 -24 hr ave	0.04 -30 day ave	0.036 -24 hr ave	0.04	0.035	0.031	0.031	0.034	15 ppmvd
Lead			0.0000257									
Sulfur Control Techn	MDEA	MDEA	MDEA	Selexol	MDEA	Selexol	Selexol	Selexol	Selexol	Selexol	MDEA	Selexol
Nox Control Technology	Diluent injection	Diluent injection	Diluent injection	Diluent/SCR	Diluent injection	Diluent/SCR	Diluent/SCR	Diluent/SCR	Diluent injection	Diluent injection	Diluent injectio	Diluent/SCR

(1) Application estimates this emission limit but does not proposed an emission limit
(2) No limit established. Fluorides from IGCC plants are below PSD significance
(3) Polk IGCC also has this emission rate effective July 2003 as set by BACT.

Source: Declaration of John Thompson, Director of the Clean Air Transition Project for the Clean Air Task Force, submitted to EPA for the Desert Rock air permit, dated November 10, 2006, page 13.

Exhibit RCF-13

EMISSIONS FROM AMPS – OHIO PLANT VERSUS RECENT IGCC PERMIT APPLICATIONS

	AMPGS	IGCC			
	Proposed Emission Rates	Sulfur control using MDEA	Sulfur control using Selexol	Nitrogen control using diluent injection	Nitrogen control using both diluent injection and SCR
	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)
SO2	0.15	0.025 - 0.033 (17% - 22%)	0.0117 - 0.019 (8% - 13%)		
NOx	0.07			0.057 - 0.07 (81% - 100%)	0.012 - 0.025 (17% - 36%)
PM	0.015	0.001 – 0.0063 (7% - 42%)			
CO	0.154	0.03 - 0.04 (19% - 26%)			
Hg	0.0000019	0.00000019 - 0.00000056 (10% - 29%)			

Source: IGCC Data from Declaration of John Thompson, Director of the Clean Air Transition Project for the Clean Air Task Force, submitted to EPA for the Desert Rock air permit, dated November 10, 2006, page 15.

Total Tons per Year of Pollutants from AMPS-Ohio and IGCC Plant of Same Size (960 MW)

Exhibit RCF-14

Emissions	AMPS–Ohio PC[1]	Taylorville-IGCC [2]	IGCC vs PC % of EMISSIONS
NO_X	3,194	1,128	35 %
SO_2	6,820	654	10 %
Particulate	1,182	636	54 %
Mercury	0.086	0.057 (0.008)	66 % (10%)
H_2SO_4	343	115	34 %
CO	7,009	1,566	22 %
VOC	167	50	30 %

1 "STAFF DETERMINATION FOR THE APPLICATION TO CONSTRUCT UNDER THE PREVENTION OF SIGNIFICANT DETERIORATION REGULATIONS FOR AMERICAN MUNICIPAL POWER GENERATING STATION LETART FALLS, OHIO", PTI NUMBER 06-08138, August 9, 2007, by Ohio Environmental Protection Agency, Table 1.

2 "Construction Permit - Prevention of Significant Deterioration Approval for Taylorville IGCC Plant", June 5, 2007, issued to Christian County Generation, Appendix Table III, page 1-4 and page 3.

RCFurman 10/2/07

Proposed Permit Emission Rates for PC Plants

Emissions	AMPS- Ohio[1]	FPL – Glades[2]	Taylor Energy Center[3]
NOx lb/MMBtu	**0.07**	**0.05**	**0.05**
SO2 lb/MMBtu	**0.15**	**0.04**	**0.04**
Particulate lb/MMBtu	**0.015**	**0.013**	**0.013**
Mercury lb/TBtu	**1.9**	**1.2**	**0.9**

1 "STAFF DETERMINATION FOR THE APPLICATION TO CONSTRUCT UNDER THE PREVENTION OF SIGNIFICANT DETERIORATION REGULATIONS FOR AMERICAN MUNICIPAL POWER GENERATING STATION LETART FALLS, OHIO", PTI NUMBER 06-08138, August 9, 2007, by Ohio Environmental Protection Agency.

2 "Air Permit Application and Prevention of Significant Deterioration Analysis for FPL Glades Power Park Glades County, Florida", prepared for Florida Power & Light Company, by Golder Associates Inc., December 2006.

3 "Air Construction/ Prevention of Significant Deterioration Permit Application for Taylor Energy Center", Prepared for JEA, Reedy Creek, City of Tallahassee and FMPA, prepared by Environmental Consulting & Technology Inc. and Sargent & Lundy, May 2007.

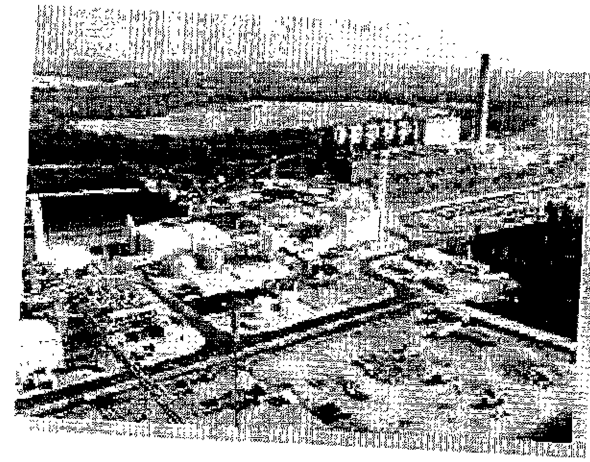
RCFurman 10/2/07

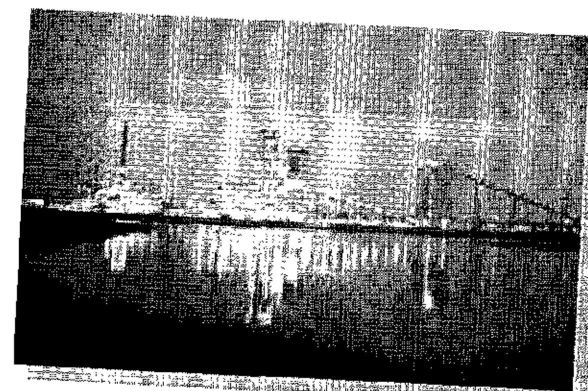
Exhibit RCF-16

IGCC Technology in Early Commercialization

U.S. Coal-Fueled Plants

- **Wabash River**
  - 1996 Powerplant of the Year Award*
  - Achieved 77% availability **
- **Tampa Electric**
  - 1997 Powerplant of the Year Award*
  - First dispatch power generator
  - Achieved 90% availability **





Nation's first commercial-scale IGCC plants, each achieving
> 97% sulfur removal
$\geq$ 90% NO_x reduction

NETL

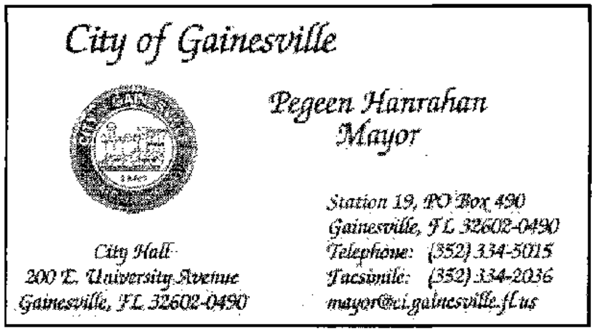
*Power Magazine ** Gasification Power Block

Source: Department of Energy/NETL Presentation, <u>Overview of Coal Gasification Technologies,</u> by Gary Stiegel, presented at NSTAR Meeting, Pittsburgh, PA, Oct. 27,2006.

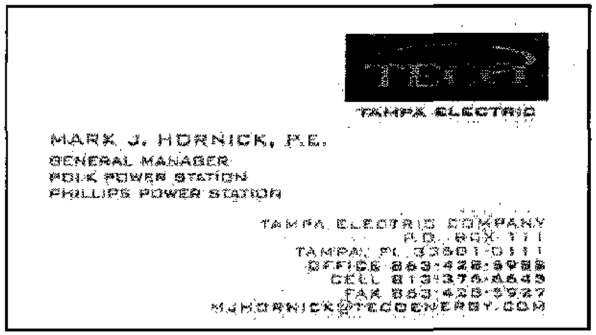
References to Contact

Exhibit RCF-17

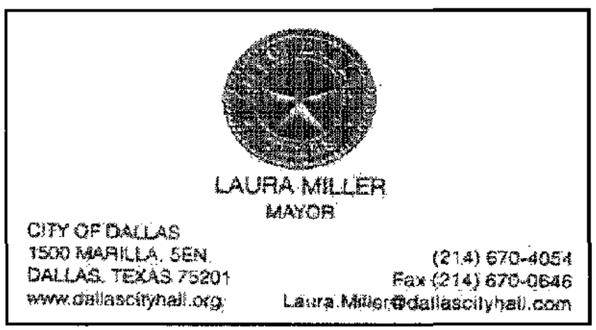
Pulverized Coal vs. IGCC Plants



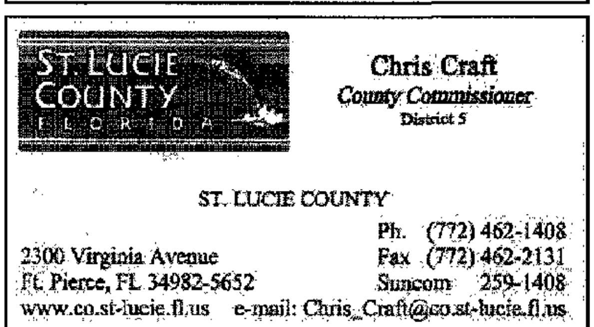
City of Gainesville hired ICF Consultants directly. ICF evaluation selected IGCC as best choice. Gainesville issued RFI for partners in IGCC plant.



Tampa Electric has operated an IGCC plant for over 10 years. Tampa Electric has announced an additional 630MW IGCC plant to be operating in 2013. The plant manager can answer any questions. Tours of the plant are available.



The Mayor of Dallas has toured the Tampa Electric IGCC plant and is knowledgeable about power plants and pollution control equipment. She has formed a coalition of 22 mayors in Texas to encourage the use of IGCC plants.



The St. Lucie County Commission voted 6 to 0 against a 1700MW PC plant proposed by FPL. Commissioner Chris Craft traveled to the Taylor County Commission hearing to advise them on St. Lucie's experience.

"It is difficult to get a man to understand something when his salary depends upon his not understanding it."

- Upton Sinclair

Exhibit RCF-18

World Gasification Survey: Summary Operating Plant Statistics 2004

117 Operating Plants

385 Gasifiers

Capacity~**45,000** MWth

Feeds

Coal **49%,** Pet. Resid. **36%**

Products

Chemicals **37%,** F-T **36%,** Power **19%**

Growth Forecast **5% annual**

Gasification Technologies Council

Exhibit
RCF-19

Commercially Operating IGCC Projects Worldwide. Table lists 14 commercially operating IGCC plants worldwide (including one now undergoing commissioning) that provide close to 3900 MW of generating capacity. Plants use a variety of feedstock coals, petroleum coke and other refinery residues. Nuon Buggenum plant recently introduced biomass to supplment its coal feedstock. The syngas-modified V94 gas turbines are Siemens designs built by Ansaldo. The Frame machines are GE designs.

Project	Startup	Rating	Feed	Product	Gasifer	Gas Turbine
Nuon (Demkolec), Buggenum, The Netherlands	1994	250 MW	coal/biomass	power	Shell	V94.2
Wabash (Global/Cinergy), Indiana USA	1995	260 MW	coal/coke	repowering	Conoco Phillips	1xFr 7FA
Tampa Electric, Polk County, Florida USA	1996	250 MW	coal/coke	power	GE/Texaco	1xFr 7FA
Frontier Oil, El Dorado, Kansas USA	1996	45 MW	coke	power/steam	GE/Texaco	1xFr 6B
SUV, Czech Republic	1996	350 MW	coal/coke	power/steam	Lurgi	2xFr 9E
Schwarze Pumpe, Germany	1996	40 MW	lignite/waste	power/methanol	Future Energy	1xFr 6B
Shell Refinery, Pernis, The Netherlands	1997	120 MW	visbreaker/tar	power/steam/H2	Shell	2xFr 6B
Elcogas S.A., Puertollano, Spain	1998	300 MW	coal/coke	power	Prenflo	1x V94.3
ISAB Energy, ERG/Mission, Italy	2000	520 MW	asphalt	hydrogen/power	GE/Texaco	2x V94.2K
Sarlux, Saras/Enron, Sardinia, Italy	2001	545 MW	visbreaker/tar	power/steam/H2	GE/Texaco	3x Fr 9E
Exxon Chemical, Singapore	2001	160 MW	ethylene tar	power/steam	GE/Texaco	2xFr 6FA
Api Energia, Falconara, Italy	2002	280 MW	visbreaker/tar	power	GE/Texaco	1xKA 13E2
Valero (Premcor), Delaware City USA	2003	160 MW	coke	repowering	Alstom GE/Texaco	2xFr 6FA
Nippon Refining (NPRC), Negishi, Japan	2003	342 MW	asphalt	power	GE/Texaco Mitsubishi	1x701F
Eni Sannazzaro, AGIP Petrolia, Italy	2006	250 MW	oil residues	power/steam/H2	Shell	V94.2K
Total generating capacity		**3872 MW**				

Source: Luke O'Keefe, Burns & Roe

Exhibit
RCF-20

Proposed IGCC and Gasification Plants North America (GTW January 2007)
This is a working reference of proposed projects in North America, compiled from a variety of sources.Five projects highlighted in yellow were awarded substantial EPAct 2005 tax incentives in December 2006.

Project/Feed	Nominal Net Output	Gasifier	Gas Turbine	Engineer	Year	Comments
Agrium, Kenai, Alaska sub-bituminous	260 MW poly*	GE Energy	GE Frame		2011	*ammonia/urea
Alma, Michigan coal	MW + poly*		N/A			*plus methanol
American Electric Power, Ohio coal	630 MW	GE Energy	2 x Fr 7FB	Bechtel	2010	
American Electric Power, West Virginia coal	630 MW	GE Energy	2 x Fr 7FB	Bechtel	2010	
Baard Energy/Rentech, Ashtabula, Ohio Illinois coal	100 MW poly*	Shell	1 x Fr 6FB			*35,000 bpd
Basin Electric , South Dakota PRB coal		GE Energy	GE Frame			
BP Edison Refinery, Carson, California pet coke	390 MW poly*	GE Energy	1 x Fr 7FB			*plus hydrogen
Citgo, Lake Charles, Louisiana pet coke	MW + poly*		N/A			*plus hydrogen
Clean Coal Power, Vandalia, Illinois coal	MW + polygen*		N/A			*100,000 bpd naptha
CoP Refineries, Various Sites pet coke	hydrogen*	CoP E-Gas	N/A			*hydrogen/steam
DKRW, Medicine Bow, Wyoming So Wyom coal	140 MW poly*	GE/Rentech	N/A			*11,000 bpd dist/naptha
Duke/Cinergy , Edwardsport, Indiana coal	630 MW	GE Energy	2 x Fr 7FB			
Energy Northwest , Port Kalama, Washington coal/pet coke	600 MW		N/A		2011	
Erora/Tenaska, Taylorville, Illinois Illinois coal	630 MW poly*	GE Energy	2 x Fr 7FB	Burns	2010	*synthetic natural gas
Erora/Tenaska, Cash Creek, Kentucky (GE Energy Financial taking 20% equity position) Ky # 9 coal	630 MW poly*	GE Energy	2 x Fr 7FB		2010	*substitute natural gas
Excelsior Energy, Holman, Minnesota (Phase 1) PRB/pet coke	606 MW *	CoP E-Gas	2 x S5000F	Fluor	2011	*450 MW power purchase agreement pending
Excelsior Energy, Holman, Minnesota (Phase 2) PRB/pet coke	606 MW	CoP E-Gas	2 x S5000F	Fluor	2012	
FutureGen Alliance, Site TBD (DOE to pay two-thirds for zero emissions demo plant) bitum/sub-bitum	275 MW poly*		N/A		2012	*plus hydrogen
GRE, North Dakota lignite	10,000 bpd*	Shell/ Siemens	N/A			*Fischer Tropsch liquids

Exhibit
RCF-21

Hunton Energy, Fort Bend County, Texas (Phase 1)						
petcoke	600 MW*	GE or CoP	N/A		2012	*with CO_2 capture and sequestration
Hunton Energy, Fort Bend County, Texas (Phase 2)						
pet coke	600 MW*	GE or CoP	N/A		2013	*with CO_2 capture and sequetsration
Indiana Gasification, Indiana (Pub Service, Vectren, Citizen's Gas to take output)						
high-sulfur coal	syngas*	GE Energy	N/A		2011	*100 MM scfd
Mississippi Power, Kemper County, Mississippi						
lignite	700 MW	Kellog Brn Root		N/A		
Mosaic/US Syngas, St. James Parish, Louisiana						
pet coke	hydrogen+poly*	GE Energy	N/A	Japan		*1.33 MM tpy ammonia 230 MM scfd syn nat gas
Mountain Energy, Idaho						
coal	hydrogen		N/A			
North West Upgrading, Edmonton, Canada						
oilsands	hydrogen, syngas*		Lurgi MPG	N/A	2010	*120 MM scfd 50,000 bpd capacity
NRG Energy, Huntley, New York						
coal	630 MW	Shell	N/A		2012	brownfield coal station
NRG Energy, Indian River, Delaware						
coal	630 MW	Shell	N/A		2011	brownfield coal station
NRG Energy, Montville, Connecticut						
coal	630 MW	Shell	N/A			existing NG comb cycle
OPTI/Nexen, Fort McMurray, Canada						
oilsands	MW + poly*	Shell	N/A		2008	*hydrogen and syngas 58,500 bpd capacity
PacifiCorp, Utah (Hunter)						
coal	250-600 MW		N/A		2014	
PacificCorp, Wyoming (Jim Bridger)						
sub-bituminous	250-600 MW		N/A		2014	
PacificCorp/MEHC, Wyoming (M&M Ranch)						
lignite	250-600 MW		N/A		2014	
Peabody, New Mexico						
coal	polygen*		N/A			*synthetic natural ga and coal to liquids
Peabody/Rentech, Midwest						
coal	polygen*		N/A			*10,000 scfd syn nat gas and 30,000 bpd
Peabody/Rentech, Montana						
coal	polygen*		N/A			*10,000 scfd syn nat gas and 30,000 bpd
Peace River Oil, Red Deer, Canada						
oilsands	MW + poly*				2010	*plus hydrogen andsyngas
Power Holdings, Jefferson Co, Illinois						
Illinois coal	syn nat gas*	GE/Bechtel	N/A		2009	*140 MM scfd SNG

Exhibit
RCF-22

Rentech, Natches, Michigan						
coal	F-T diesel*		N/A			Fischer-Tropsch
Rentech Energy Solutions, Mingo Co, West Virginia						
coal	F-T diesel*		N/A			*20,000 bpd F-T liquids
Rentech/Royster, East Dubuque, Illinois						
coal	75 MW poly*	CoP E-Gas	N/A	Kiewit		*930 tpd ammonia and 1800 bpd fuel
Sask Power, Canada						
pet coke	300 MW poly*		N/A	Jacobs		*plus hydrogen and syngas
Sherritt International, Dodds-Roundhill, Canada						
oilsands	polygen*					*hydrogen and syngas CO_2 capture for EOR
Southern Company, Orlando, Florida						
PRB coal	285 MW	KBR Transport	1 x Fr 7FB	KBR		
Southwestern Power, Bowie Station, Arizona						
coal			N/A			
Steelhead, Southern Illinois						
Illinois coal	630 MW poly*	CoP E-Gas	2 x S5000F	Fluor		*100 MM scfd syn nat gas
Summit Power, Washington						
coal	365 MW poly*		1 x S5000F			*plus syn natural gas
Suncor Energy, Voyager II, Fort McMurray, Canada						
pet coke	polygen*		N/A		2012	*hydrogen and SNG
Synenco/Sinopac, Northern Lights Upgrader, Edmonton, Canada						
oilsands	poygen*	GE license	N/A			*hydrogen and syngas 100,000 bpd capacity
Synfuel, Ascension, Louisiana						
lignite	MW + poly*	GE Energy	GE Frame			*chemicals, SNG,acid
Synfuel, Oklahoma						
coal	polygen*	Siemens	N/A			*Fischer -Tropsch liquids
Tampa Electric Unit-2, Polk County, Florida						
bituminous	630 MW	GE Enery	2 x Fr 7FB		2013	
Texas Energy/Eastman, Longview, Texas						
pet coke	polygen*	GE Energy	N/A			*syngas, methanol
Tondu-Nueces, Corpus Christi, Texas						
coal/pet coke	630 MW	Shell	2 x S5000F			
West Hawk Development, Northwest Canada						
coal	syn nat gas*		N/A			*550 MM scfd
WMPI, Gilberton, Pennsylvania						
anthracite waste	133 MW poly*	Shell	N/A			*5,000 bpd FT diesel and 4,000 tpy sulfur
Xcel, Colorado						
coal	300-350 MW*				2013	*with CO_2 capture and sequestration

Source: EPRI data, news releases, websites, permit applications, presentations, GTW industry contacts

Exhibit RCF-23

Proposed IGCC and Gasification Plants Ex-North America (GTW January 2007)
This is a working reference of proposed projects being developed around the world. Many of them are being built for polygeneration of electric power and chemical products from low grade feedstock and waste. Several will operate to capture and store carbon dioxide.

Project/Feed	Output	Gasifier	GT Model	Engr	Year	Products
Bharat Heavy Electricals, Auraiya, India						
coal	125 MW*	BHEL Fluid Bed		BHEL	2009	*demo plant
BP/CoP/Shell, Peterhead, United Kingdom						
natural gas	475 MW poly*	Thermal Reformer			2010	*hydrogen fuel and CO2 capture for EOR injection
Centrica/Progressive Energy, Teesside 1, United Kingdom						
coal/pet coke	800 MW poly*				2012	*hydrogen fuel and CO2 capture for EOR injection
Centrica/Progressive Energy, Teesside 2, United Kingdom						
coal/pet coke	800 MW poly*				2013	*hydrogen fuel and CO2 capture for EOR injection
China Fertilizer BGL Demo Plant, China						
lignite		BGL				
Clean Coal Power Demo Plant, Iwaki City, Japan						
bituminous	250 MW	MHI air-blown	1 x M701DA	MHI	2007	42% net plant efficiency LHV
E.On/PowerGen, Killingholm, Germany						
coal						
Fujian Refinery, China						
asphalt	450 MW poly*	Shell	2 x Fr 9E	FW		*3 x 1200 tpd hydrogen
Hatfield/KRU Russia, Hatfield, United Kingdom						
coal	430 MW*					*CO2 capture for enhanced oil recovery injection
HRL/Harbin Power, Victoria, Australia						
brown coal		HRL Fluid Bed			2010	
Indian Oil Refinery, Madras, India						
residue	MW + poly*					*hydrogen, also steam
Jindal Steel, Orissa States, India						
high ash coal	syngas fuel*	Lurgi Mark IV				*320,000 Nm3/hr
Lotos Group, Gdansk, Poland						
asphalt	MW + poly*	Shell				*1600 tpd feed, hydrogen
Nuon, Eemshaven, Netherlands						
coal/biomass	1200 MW	Shell license		Lummus	2011	
Progressive Energy, South Wales, United Kingdom (multiple sites)						
coal/pet coke	460 MW*					* CO2 capture for enhanced oil recovery injection
RWE, Germany						
lignite	450 MW*				2014	*360 MW net and 300 tph carbon dioxide capture
Schwarze Pumpe, Spreetal, Germany						
lignite	300 MW poly*	Siemens	1 x S3000E		2009	*plus methanol
Schwarze Pumpe, Spreetal, Germany						
lignite	polygen*	Siemens			2009	*3000 bpd F-T liquids

Exhibit
RCF-24

SES/Hai Hua, Zaozhuang, Shandong, China				
waste coal	MW + poly*	U-Gas		*25 MM scfd syn nat gas
Sines Refinery, Sines, Portugal				
heavy oil	500 MW poly*		2013	*plus methanol
Shell/Anglo American, Latrobe, Victoria, Australia				
coal	MW + poly*	Shell		*coal-to-liquids, CO_2 capture
Shenhua/Shell, Inner Mongolia, China				
coal	polygen*	Shell (2)	2007	*hydrogen and 1 MM tpy liquids
Shenhua/Shell, Ningxia, China			AMEC	
coal	polygen*	Shell		*3 MM tpy F-T liquids
Shenhua/Sasol, Multiple sites, China				
coal	polygen*	Sasol		3 x 3 M tpy F-T liquids
Stanwell ZeroGen, Queensland, Australia				
sub-bitum	100-300 MW*	Shell	2010	*CO_2 capture for enhanced oil recovery injection
Statoil, Halten, Norway				
natural gas	polygen*	Shell		*CO_2 capture for enhanced oil recovery injection

Source: EPRI data, news releases, websites, permit applications, presentations, GTW industry contacts

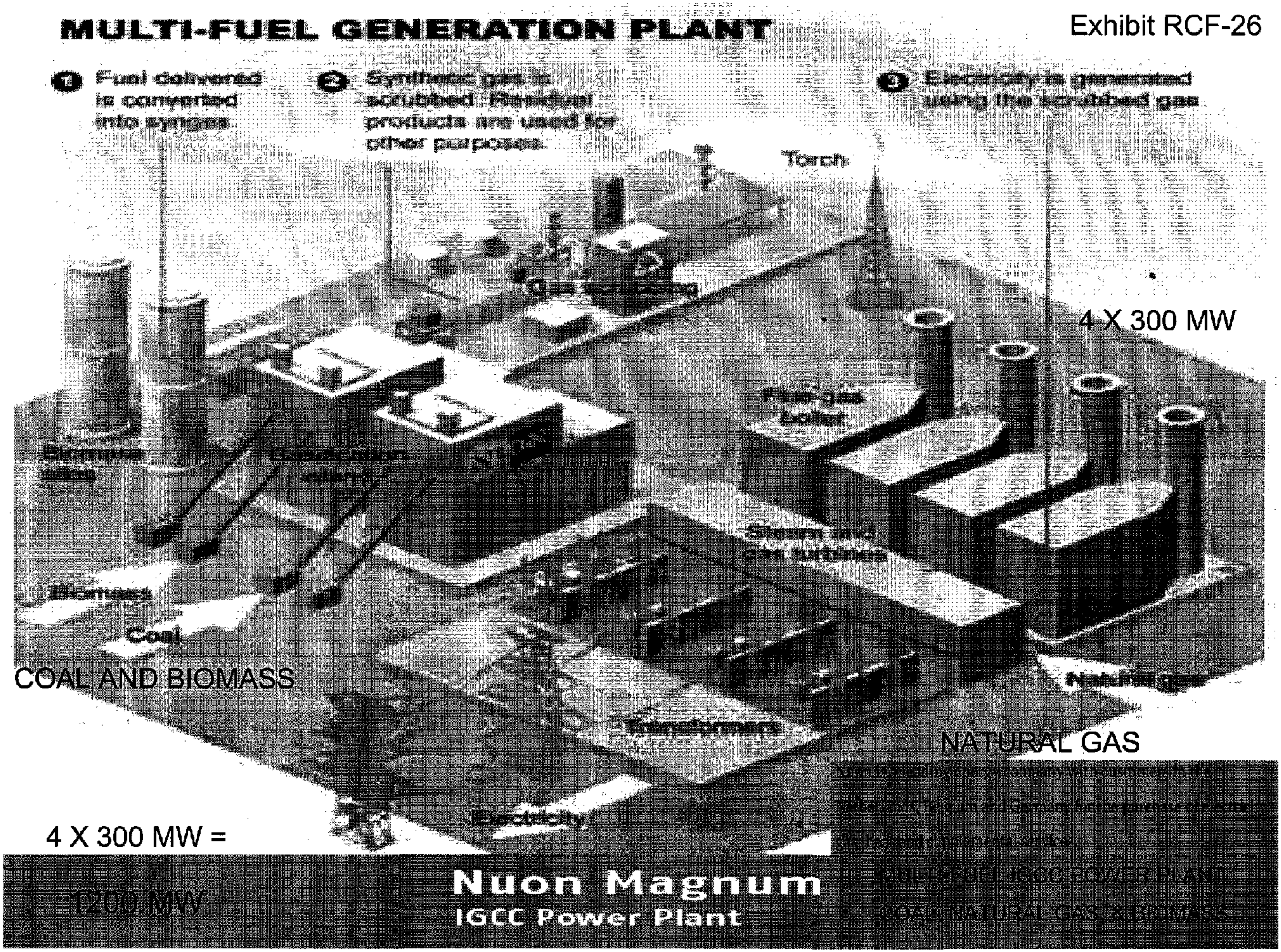
Exhibit
RCF-25

Proposed "carbon capture and storage" power plant projects (275 MW and above).
Europe, particularly the UK, taking lead in number of proposed power projects featuring CO_2 capture and storage. Recent reopening of Hatfield Colliery, with support of Russion energy interests, may be forerunner to first plant to enter operation. According to list, a number of large commercial plants could be running before US FutureGen demo plant scheduled for 2012 startup.

Company and project	Plant output	Capture technology	Start
Progressive Energy, Teeside, UK petcoke	800 MW +H2	IGCC + shift + precombustion	2009
BP Peterhead/Miller, Scotland natural gas	475 MW	Auto reformer + precombustion	2010
Powerfuel, Hatfield Colliery, UK coal	900 MW	IGCC + shift + precombustion	2010
BP Carson, USA petcoke	500 MW	IGCC + shift + precombustion	2011
E.On, Killingholme, UK coal	450 MW	IGCC + shift + precombustion	2011
SaskPower, Saskatchewan, Canada lignite	300 MW	PC + post-combustion or oxyfuel	2011
Siemens/Spreetal, Germany coal	1000 MW	IGCC + shift + precombustion	2011
Statoil/Shell, Draugen, Norway natural gas	860 MW	NGCC + post-combustion amine	2011
FutureGen, USA coal	275 MW	IGCC + shift + precombustion	2012
Stanwell, Queensland, Australia coal	275 MW	IGCC + shift + precombustion	2012
Vattenfall/Schwarze Pumpe, Germany lignite	300 MW	Oxyfuel + post-combustion	2012
RWE, Germany coal	450 MW	IGCC + shift + precombustion	2014
RWE, Tilbury, UK coal	500 MW	SCPC + post-combustion	2016

Source: Based on 2006 report by Gibbins and Chalmers, "Carbon Capture and Storage", Mech Engr Dept., Imperial College London, plus company websites, press releases, industry communications.

Exhibit RCF-26

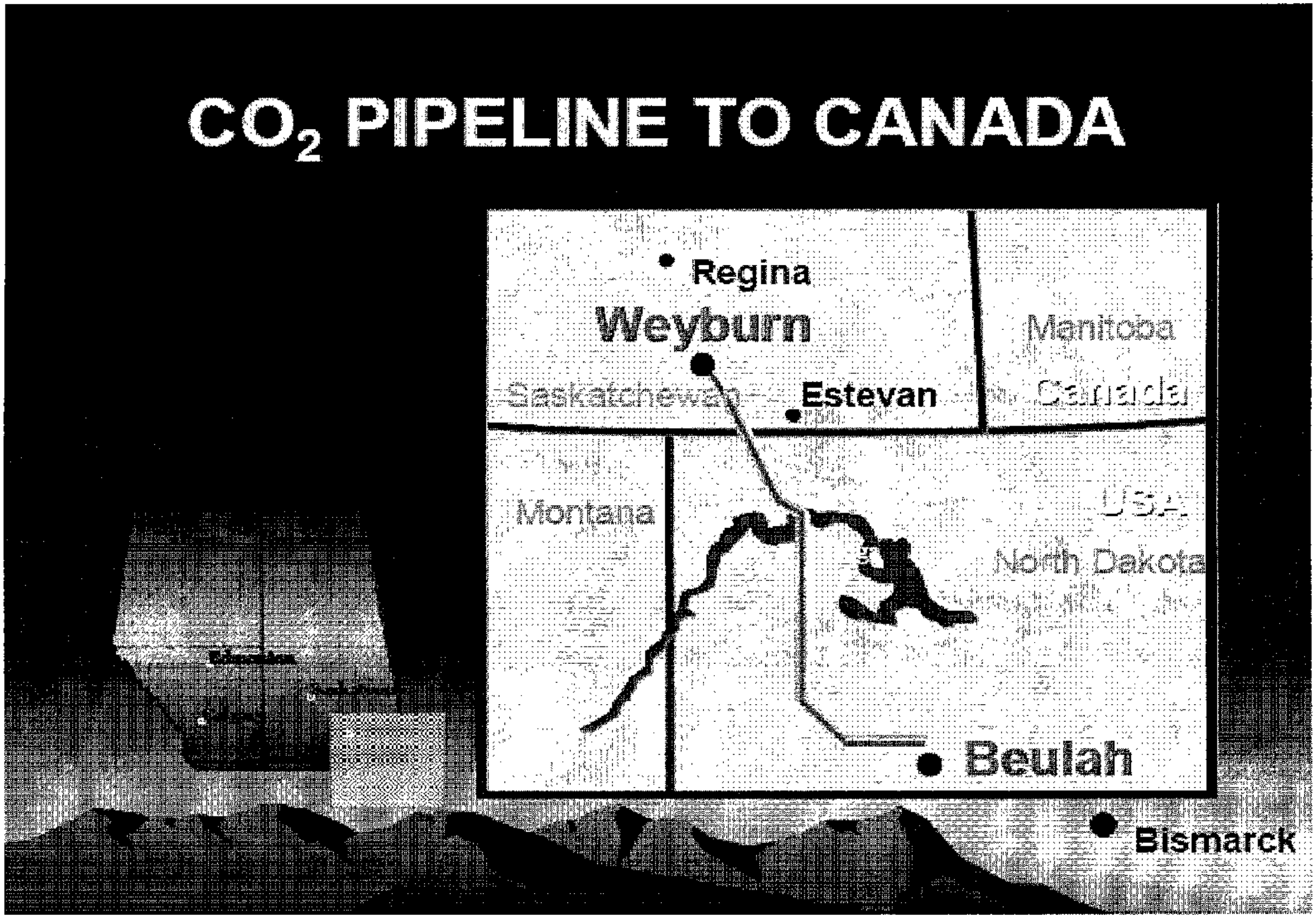


THE GREAT PLAINS SYNFUELS PLANT

Exhibit RCF-27

The Gasification Plant shown in the foreground began Operating in 1984 in North Dakota & uses 6 million tons per year of Lignite Coal to Produce 54 Billion cubic feet of Synthetic Natural Gas (SNG) and 4 million tons per year of Carbon Dioxide used for EOR. The Antelope Valley Power Plant shown in the background uses 5 million tons of Lignite Coal for the two 440 MW Units.

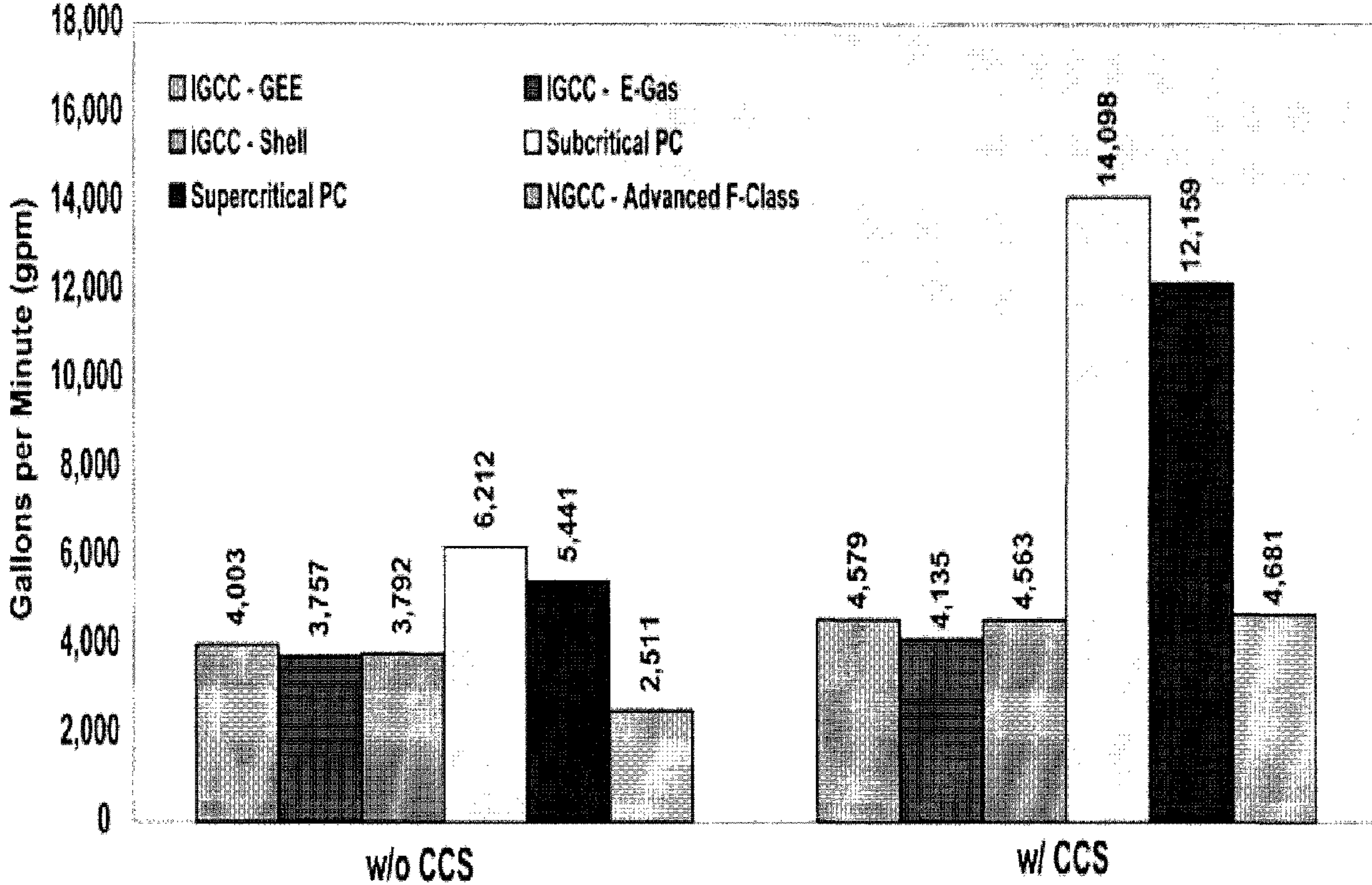
(Source: "The New Synfuels Energy Pioneers" by Stan Stelter, Introduction by Former President Jimmy Carter, published by Dakota Gasification Co.- 2001, A subsidiary of Basin Electric Power Cooperative, page 48)



(Source: Experience Gasifying ND Lignite by Al Lukes, Dakota Gasification Company, The Great Plains Synfuels Plant presented at the Montana Energy Future Symposium)

Exhibit RCF-29

Figure 5. Plant Raw Water Usage



Source: "Fossil Energy Power Plant Desk Reference", DOE/NETL-2007/1282, May 2007, Overview-5, Figure 5.

Thermal Generation Technology Spectrum

	Conditions	Net Plant Efficiency	Net Plant Heat Rate (HHV)
Subcritical	2,400 psig 1,050 °F / 1,050 °F	35%	9,751 Btu/kWh
Subcritical HARP Cycle	2,400 psig 1,080 °F / 1,080 °F	37%	9,300 Btu/kWh
Supercritical	3,500 psig 1,050 °F / 1,075 °F	38%	8,981 Btu/kWh
Advanced Supercritical	Limit of 4,710 psig 1,130 °F / 1,165 °F / 1,165°F	42%	8,126 Btu/kWh
Ultra-Supercritical	5,500 psig 1,300 °F main steam	44%	7,757 Btu/kWh

BLACK & VEATCH

Source: "Black & Veatch Supercritical Plant Technology Overview", by Ron Ott, Senior Vice President - Coal Program Director, presented at CSX Coal Forum, February 18-20, 2004.

Subcritical vs Supercritical Technology

	Subcritical	Supercritical
Number of Units	31	16
Average Age	17	20
Size Range	400 – 850 MW	400 – 850 MW
Average Size	565 MW	684 MW
Minimum Capacity Factor	50	50
Availability Factor	83.7	83.2
Forced Outage Rate	6.6	6.7
Capacity Factor	70.2	70.1

NERC GADS Data for 1994 – 1998 shows comparable reliability for supercritical and subcritical plants.

02/18/04

RO-16

BLACK & VEATCH

Source: "Black & Veatch Supercritical Plant Technology Overview", by Ron Ott, Senior Vice President - Coal Program Director, presented at *CSX Coal Forum*, February 18-20, 2004.

Major Boiler Manufacturers

Boiler OEM	Recent Supercritical Units				
	Unit Name	Size (MW)	Location	COD	Steam Conditions
Alstom	Yunghung 1 & 2	800	Korea	2002	3,625 psig / 1,056 °F / 1,056 °F
	Niederaussem K	1,000	Germany	2002	3,916 psig / 1,076 °F / 1,112 °F
B&W	Millmerran 1&2	400	Australia	2002	3,596 psig / 1,054 °F / 1,105 °F
	Zimmer	1,300	USA	1991	3,480 psig / 1,000 °F / 1,000 °F
Babcock Hitachi	Hitachinaka 1	1,000	Japan	Planned for 2003	3,627 psig / 1,119 °F / 1,116 °F
	Tachibanawan	1,050	Japan	2000	3,770 psig / 1,121 °F / 1,135 °F
	Lippendorf F,S	933	Germany	2000	4,060 psig / 1,030 °F / 1,030 °F
FW	Taishan 1&2	710	China	Sold in 2002	3,770 psig / 1,009 °F / 1,043 °F
IHI	Hekinan 5	600	Japan	2002	3,625 psig / 1,059 °F / 1,104 °F
	Isogo 1	600	Japan	2002	4,060 psig / 1,021 °F / 1,135 °F
MHI	FP-1 2	600	Taiwan	1998	3,770 psig / 1,000 °F / 1,050 °F
	Hirono 5	600	Japan	2002	3,625 psig / 1,112 °F / 1,112 °F
Mitsui Babcock	Hemweg	680	Holland	1992	3,770 psig / 1,004 °F / 1,054 °F
	Meri Pori	560	Finland	1993	4,060 psig / 1,004 °F / 1,040°F

BLACK & VEATCH

Source: "Black & Veatch Supercritical Plant Technology Overview", by Ron Ott, Senior Vice President - Coal Program Director, presented at CSX Coal Forum, February 18-20, 2004.