Burns & McDonnell
SINCE 1898

February 5, 2004

Progress Energy Florida, Inc.
Attn: John M. Robinson, P.E.
Manager, Engineering & Commercial Support, Plant Construction
410 S. Wilmington Street
PEB 9A
Raleigh, NC 27601

Progress Energy Florida, Inc.
Solid Fuel Resource Feasibility Study
Project Close-Out - No. 35076

Dear Mr. Robinson:

Burns & McDonnell appreciates having had the opportunity to provide our professional consulting services to the Progress Energy Florida, Inc. (Progress) by completing the Solid Fuel Resource Feasibility Study (Study). These professional services were provided as defined in the Scope of Services of Amendment No. 3 to Contract No. 58146 between the Progress and Burns & McDonnell, dated October 27, 2003 (Agreement).

Burns & McDonnell's final Report on the Study was issued January 30, 2004. We believe that the issuance of the final report completed the services required under the Agreement. Burns & McDonnell has sent invoices for the full payment from Progress for the agreed to maximum fee provided in the Agreement. Therefore, Burns & McDonnell intends to close this project at this time.

If you feel there are outstanding services remaining to be provided on this project, please contact me at your earliest convenience. Otherwise, this correspondence serves as notice of completion of the services under the Agreement as of January 30, 2004.

Please feel free to call at anytime to discuss questions you may have or if you need any other assistance. You can reach me at (816) 822-3392.

Sincerely,

CONFIDENTIAL
DECLASSIFIED
Jeff Greig
Project Manager

MH 1-8-07

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 041393-EI EXHIBIT NO. 21
COMPANY/
WITNESS:
DATE: 6/2/05

9400 Ward Parkway
Kansas City, Missouri 64114-3319
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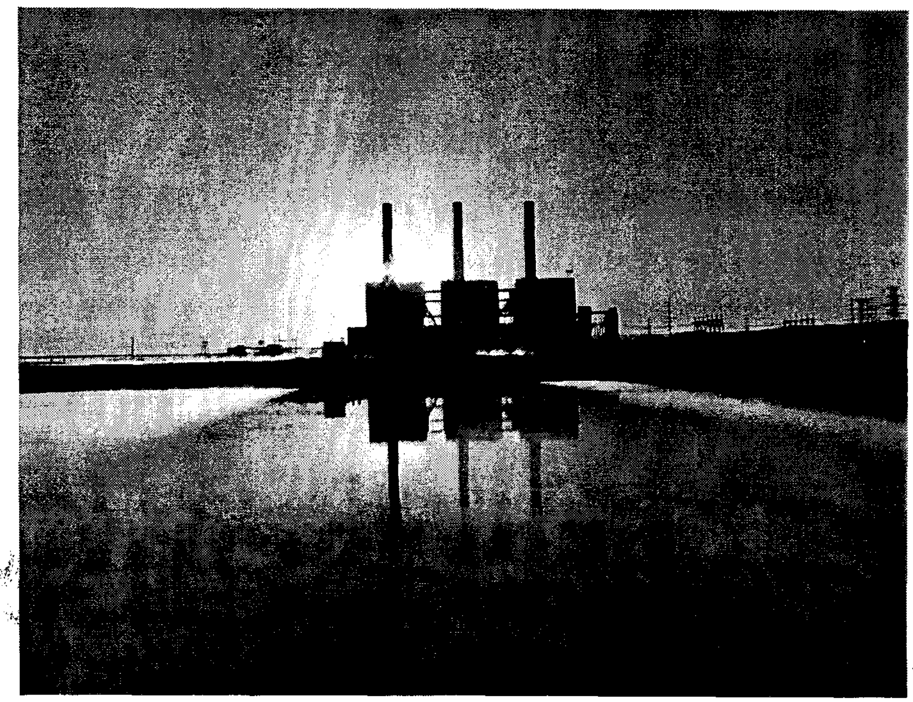
# Solid Fuel Resource Feasibility Study

Prepared For

Progress Energy

Progress Energy Florida, Inc.



January 2004
Project 35076

Burns & McDonnell
SINCE 1898

January 30, 2004

Progress Energy Florida, Inc.
Attn: John M. Robinson, P.E.
Manager, Engineering & Commercial Support, Plant Construction
410 S. Wilmington Street
PEB 9A
Raleigh, NC 27601

Dear Mr. Robinson:

Burns & McDonnell is pleased to submit this Solid Fuel Resource Feasibility Study prepared for Progress Energy Florida, Inc. The study evaluates available options for developing a new solid fuel generation facility in Florida; including Pulverized Coal, Circulating Fluidized Bed, and Integrated Gasification Combined Cycle technologies using various alternative fuels.

Issues addressed within the evaluation include:

- Technology Assessment
- Fuel Supply Evaluation
- Economic Analysis
- Environmental Permitting Assessment
- Siting Considerations
- Schedule Issues

We are pleased to assist Progress Energy Florida, Inc. with this evaluation, and we look forward to working with you in the future. If you have any comments or questions, please contact me at (816) 822-3392.

Sincerely,

BURNS & MCDONNELL

Jeff Greig
Manager, Project Development

Enclosure

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# Section 1

# Executive Summary

# SECTION 1
# EXECUTIVE SUMMARY

## 1.1 INTRODUCTION

Progress Energy Florida, Inc. (Progress) retained Burns & McDonnell (B&McD) to evaluate the feasibility of developing and installing a new solid fuel generation resource (Project) within Florida (Feasibility Study). This study did not evaluate a particular site, therefore, a specific siting study is recommended so that specific site details can be considered to perform a more detailed analysis. The Feasibility Study consisted of the following five primary components:

(1) Technology Assessment (Section 2)
(2) Fuel Supply Evaluation (Section 3)
(3) Economic Analysis (Section 4)
(4) Environmental Permitting Assessment (Section 5)
(5) Siting Considerations (Section 6)
(6) Schedule Issues (Section 7)

The proposed Project would consist of multiple units with a total potential buildout size of 1,000 MW. Individual unit blocks could range from a nominal 250 MW to 750 MW units. Larger single boiler units are possible in Pulverized Coal (PC) plants. Fuel for the Project could be from a number of alternatives including Powder River Basin (PRB) coal from Wyoming, Eastern Bituminous coal from the central Appalachian (CAPP) or northern Appalachian region (PITT), Illinois Basin coal (ILB), imported coal from Columbia, or petroleum coke. No specific site has been identified for the Project to date.

The purpose of the Feasibility Study is to provide an overview evaluation of the following questions:

- Is a solid fuel generation resource in Florida feasible?
- What are the relative economic costs of gas-fired generation versus solid fuel resources for baseload energy requirements?
- What are the current solid fuel generation technologies used in the power industry?
- What are the comparative costs, performance, and emissions characteristics of different solid fuel generation alternatives?
- What are the comparative costs of alternative solid fuels that can be delivered to Florida and how do they compare to natural gas?

- What are the environmental requirements and permitting schedule for a solid fuel generation resource in Florida?
- What are the considerations to address in siting a new solid fuel generating plant?

The following sections summarize the results of the five Feasibility Study components.

## 1.2 SUMMARY OF TECHNOLOGY ASSESSMENT

Burns & McDonnell's focus in the Technology Assessment was to evaluate the conceptual design issues with installing a new solid fuel power generation facility in Florida. The assessment investigated the costs, performance, emissions and technologies of potential power plant configurations.

The assessment covered four basic types of power plant technologies currently used in the industry for the installation of solid fuel generation capacity:

- Subcritical Pulverized Coal (PC)
- Supercritical Pulverized Coal
- Circulating Fluidized Bed (CFB)
- Integrated Gasification Combined Cycle (IGCC)

The base case identified in the study was developed around the use of low sulfur PRB coal as the design fuel. The study also reviewed the advantages, disadvantages, and cost impacts of the following of issues:

- Plant sizes of 500 MW, 750 MW and 1000 MW in single or multiple unit configurations
- Alternate fuels ranging from low sulfur imported coal to high sulfur bituminous and pet coke
- Greenfield versus brownfield site location
- Coastal versus inland site location
- Wet versus dry cooling systems
- Wet versus dry flue gas desulfurization (FGD)
- Zero Liquid Discharge (ZLD) system

A comparison of the four primary technology options is provided in Table 1-1 for PRB coal and detailed in Section 2.

**Table 1-1**
**Summary of Technology**

| Criteria | PC Subcritical | PC Supercritical | CFB Unit | IGCC Unit |
|---|---|---|---|---|
| Plant Size<br>Number of Units | 750 MW (Net)<br>1 x 750 | 750 MW (Net)<br>1 x 750 | 750 MW (Net)<br>3 x 250 MW | 500 MW (Net)<br>2 x 250 MW |
| Operating Conditions | Subcritical<br>2520psig/1050F/1050F | Supercritical<br>3500psig/1050F/1050F | Subcritical<br>2520psig/1050F/1050F | Subcritical<br>1900psig/1050F/1050F |
| Heat Rate (Design) | 9,377 Btu/kWh | 9,115 Btu/kWh | 9,914 Btu/kWh | 8,900 Btu/kWh |
| **Emissions Control** | | | | |
| $NO_x$ | SCR<br>(0.07 lb/MMBtu ) | SCR<br>(0.07 lb/MMBtu ) | SNCR<br>(0.07 lb/MMBtu) | Steam/Diluent Inj. &<br>Dry Low NOx Burners<br>(0.07 lb/MMBtu) |
| SO2 | FGD system required<br>Dry Scrubber –<br>(Low Sulfur Coal)<br>Wet Scrubber –<br>(Higher Sulfur Coals) | FGD system required<br>Dry Scrubber –<br>(Low Sulfur Coal)<br>Wet Scrubber –<br>(Higher Sulfur Coals) | FGD not necessary.<br>Removal via<br>Limestone & Flyash<br>Reinjection<br>(Low Sulfur Coal)<br>Polishing Scrubber –<br>(High Sulfur Coals) | Syngas scrubbing<br>95-99% removal |
| Particulate | Baghouse<br>(Low Sulfur Coal)<br>ESP<br>(High Sulfur Coal) | Baghouse<br>(Low Sulfur Coal)<br>ESP<br>(High Sulfur Coal) | Baghouse | Not required |
| Mercury | Injection of flyash and/or activated carbon with Dry Scrubber.<br>Wet Scrubber with reagent addition. | Injection of flyash and/or activated carbon with Dry Scrubber.<br>Wet Scrubber with reagent addition. | Injection of flyash and/or activated carbon upstream of Baghouse. | Not required |
| **Capital Cost** | | | | |
| Capital Cost<br>(Greenfield)<br>2010$/KW | $1377 (Dry FGD)<br>$1425 (Wet FGD) | $1402 (Dry FGD)<br>$1449 (Wet FGD) | $1454/kW<br>(No Polishing Scrubber) | $1800/kW |

| O&M Costs (2003$) | | | | |
|---|---|---|---|---|
| Fixed | $17.60/kW-yr (Dry) $19.36/kW-yr (Wet) | $17.60/kW-yr (Dry) $19.36/kW-yr (Wet) | $19.95/kW-yr (No Scrubber) | $23.60/kW-yr |
| Non-Fuel Variable | $2.76/MWh (Dry) $2.59/MWh (Wet) | $2.71/MWh (Dry) $2.55/MWh (Wet) | $2.60/MWh (No Scrubber) | $3.35/MWh |
| **Combustion Byproducts** | | | | |
| Structural Fill (Road Base) | Yes | Yes | Yes | Yes |
| Cement Replacement | Yes (Wet Scrubber) No (Dry Scrubber) | Yes (Wet Scrubber) No (Dry Scrubber) | No | No |
| Gypsum Product | Yes (Wet Scrubber) No (Dry Scrubber) | Yes (Wet Scrubber) No (Dry Scrubber) | No | No |
| **Water Usage/Discharge** | | | | |
| Average Water Usage | 12,500 gpm | 12,150 gpm | 12,500 gpm | 2,800 gpm |
| Wastewater Discharge | 2,000 gpm | 1,950 gpm | 2,000 gpm | 450 gpm |
| **Coal Assumed** | | | | |
| | PRB fuel | PRB fuel | PRB fuel | PRB fuel |

All three of the conventional combustion technologies: Subcritical PC, Supercritical PC, and CFB, are viable and prudent technologies for Progress to evaluate in determining the best application for a new solid fuel generation resource in Florida.

- The primary advantage of the subcritical PC unit is lower overall capital costs and more operating history than the supercritical PC and CFB technologies.
- The primary advantage of the supercritical PC unit is improved performance and lower emissions compared to a subcritical unit.
- CFB technology would permit Progress to utilize a wider range of possible fuels including opportunity fuel such as petroleum coke.

B&McD recommends all three technologies be further evaluated in combination with alternative fuel supplies.

IGCC technology is a newer technology to the power generation market and has experienced reliability issues in the past that make this technology less desirable. Many of the coal gasifier plants have experienced excessive down-time for design modifications and replacement of systems. There are IGCC technology suppliers that are claiming higher reliability, lower capital costs, and lower operating costs. However, such characteristics have not been demonstrated in utility plants constructed to date. Therefore, B&McD believes IGCC plant technology using coal gasifiers requires further development to be considered a reliable technology. B&McD does not recommend Progress further consider IGCC technology as a viable alternative.

## 1.3 SUMMARY OF FUEL SUPPLY EVALUATION

Hill and Associates (H&A) was retained to evaluate potential solid fuel sources suitable to supply the Project in Florida. Because the precise location of the proposed plant site is unknown, it was assumed that all coal will be delivered to the Tampa area in central Florida.

The fuels considered for the Project were as follows:

- Powder River Basin (PRB) coal from Wyoming
- Eastern Bituminous coal from the central Appalachian (CAPP) or northern Appalachian (PITT) regions
- Illinois Basin coal (ILB)
- Imported Columbian coal
- Petroleum coke

H&A prepared a delivered price forecast for the period 2006 to 2030 for a generic plant site in central Florida which is summarized in Figure 1-1. A delivered natural gas price forecast (RFP Gas) based on assumptions provided by Progress in the Hines IV Power Supply RFP document issued in October 2003 is also presented in Figure 1-1. This gas pricing forecast estimates commodity gas prices will decline from current levels to approximately $3.60/MMBtu in 2008, and then increase at an approximate 2.5 percent rate. The total gas costs include an added transportation component of approximately $0.55/MMBtu. A gas cost sensitivity forecast (Reference Gas) was prepared by B&McD using Henry Hub futures pricing (2004-2007) referenced from current pricing on the New York Mercantile Exchange

(NYMEX) with an added transportation component equal to the RFP gas forecast. Beyond 2007, the commodity cost for the reference gas was escalated at a constant 2.5%. Figure 1-1 presents the results of both gas cost forecasts for comparison. The higher reference gas forecast was used to perform a sensitivity analysis of the benchmark combined cycle resource alternative. As indicated, current futures for natural gas supply remain very strong through 2007 and do not decline below $4.50/MMBtu.

As indicated in Figure 1-1, the lowest cost fuel alternative on a $/MMBtu basis is high sulfur pet coke delivered from the Gulf region to the Gulf coast of Florida. The next lowest cost solid fuel alternatives are imported coal from Columbia and Illinois Basin coal. For each solid fuel alternative, barge delivery is slightly lower than rail delivery into inland Florida due to lack of competition between rail carriers in Florida. CSX is the dominant rail, and has very little competition beyond the northern areas of Florida.

Each of the following fuel alternatives is evaluated in the economic analysis.

- PRB Rail Delivery to Florida
- CAPP Rail Delivery to Florida
- ILB Rail Delivery to Florida
- PITT Rail Delivery to Florida
- Columbian IMPORT via Vessel to Florida Coast
- PETCOKE (6% S) Vessel Delivery to Florida Coast
- Natural Gas (NG) RFP Forecast
- Natural Gas (NG) Reference Forecast

## 1.4 SUMMARY EVALUATION OF ECONOMIC ANALYSIS

B&McD prepared a number of pro forma economic analyses of various solid fuel project and fuel alternatives. A twenty-year economic analysis was prepared based on the estimated capital costs, performance, fuel costs, and operating costs of each Project alternative. The results of the solid fuel Project alternatives were compared against the estimated costs of a combined cycle expansion of the Hines station under the RFP natural gas cost forecast and an alternate higher gas cost sensitivity based on the reference gas cost projection.

**Figure 1-1**

**Delivered Fuel Cost Forecast**

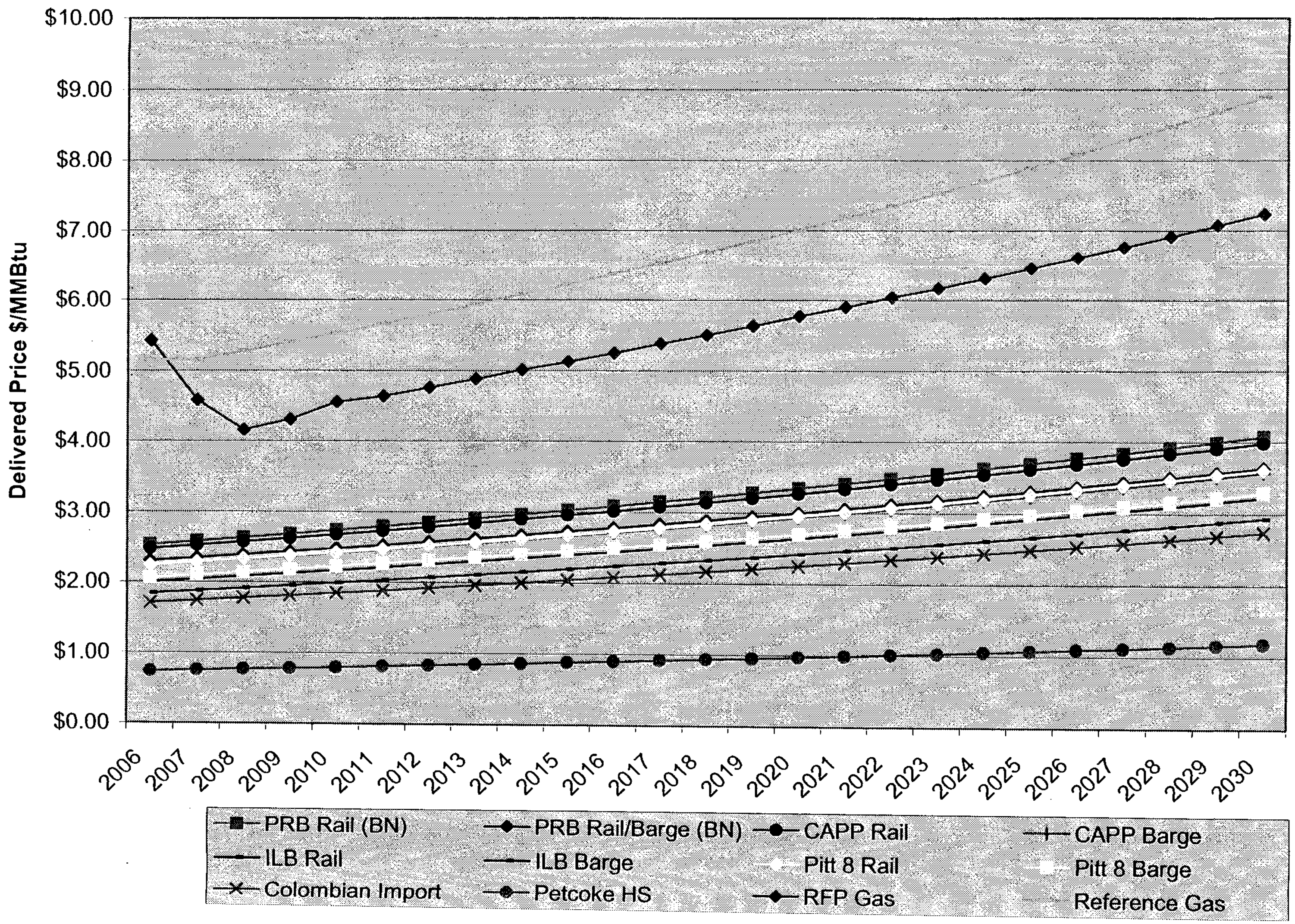


Figure 1-2 presents the comparison of 500 MW greenfield PC units under the various fuel alternatives against the 500 MW combined cycle unit under the RFP gas forecast and the higher reference gas sensitivity. As indicated, none of the greenfield 500 MW PC unit alternatives resulted in a levelized busbar cost that was lower than the combined cycle expansion case, even under the higher reference gas cost sensitivity. Imported coal and Illinois Basin were the lowest cost fuel alternatives for a 500 MW subcritical PC unit.

Figure 1-3 presents the comparison of 500 MW greenfield units under the various technology alternatives. The lower cost imported coal and Illinois basin fuels are assumed for the PC units and IGCC plant. Pet coke is also considered as a fuel source for a CFB unit in a 100% firing case and a 50%/50% blended case with Illinois basin coal. The results of the analysis in Figure 1-3 indicate that utilizing pet coke as a fuel source in a CFB unit can be a cost-effective combination. The 100% fired pet coke and CFB alternative is now a lower cost option than the 500 MW combined cycle unit under the reference gas sensitivity. However, due to potential operational issues in firing 100% pet coke, the 50%/50% blended case is a more viable alternative for comparison.

Figure 1-3 also identifies that there is little life cycle cost difference between subcritical and supercritical PC units. Subcritical units have a slightly lower capital cost while supercritical units have slightly better performance. Over a 20 year analysis, the overall costs are very similar. Most utilities selecting supercritical technology are basing the decision on improved emissions performance. Figure 1-3 further confirms that IGCC technology is not recommended for further consideration. The main drivers in the higher costs of the IGCC alternative are the higher capital cost and a lower availability which was assumed for this new technology.

Figure 1-4 presents a comparison of overall economic results for feasible solid fuel generation resources to be evaluated by Progress in further siting and preliminary engineering studies. The most cost-effective solid fuel projects incorporate the following characteristics.

- Brownfield site locations that offer infrastructure and operating cost savings are competitive.
- Competitive PC unit fuels are imported Columbian coal and Illinois basin coal. Pet coke can also be blended and co-fired in a PC boiler with Illinois basin coal to take advantage of its lower delivered cost. However, the percentage of pet coke that can be cofired in a PC unit is limited and changing to a different blend requires retuning the boiler. Also, imported coal will have higher risk due to political instability in the source country and ocean shipping risk.

- CFB technology to more fully take advantage of lower delivered costs for pet coke appears advantageous. While burning 100% pet coke in a CFB unit can be operationally challenging, high percentages (i.e., greater than 75%) are being achieved at an existing CFB plant in Jacksonville, Florida. CFB units also offer more fuel flexibility compared to PC technology which can be beneficial to keep long-term fuel costs down.
- Larger unit sizes such as 750 MW will result in improved economics compared to 500 MW blocks for the PC units. Further, larger plant sizes such as 2 x 750 MW will result in improved economics due to reduced capital costs and reduced O&M costs.
- Subcritical and supercritical technologies are both viable, reflect similar life cycle costs, and are selected frequently based on operating preferences and environmental considerations.
- Florida is unique location. Due to the long distance from domestic coal resources and limited transportation competition, the delivered fuel costs of several solid fuel alternatives are high compared to other coal plants in the southeast. Barge or vessel delivery offers slightly lower costs than rail delivery and offers greater fuel flexibility. The possibility of siting a new unit that could generate barge versus rail competition should be pursued.
- Sensitivity analyses indicates that capital cost and capacity factor are the two most significant factors affecting the economics of a solid fuel unit. Delivered fuel cost by far has the strongest impact on the overall economics of a combined cycle unit.
- Solid fuel generation resources are significantly more capital intensive than gas combined cycle resources and will be subject to higher construction labor and inflation risk during construction.

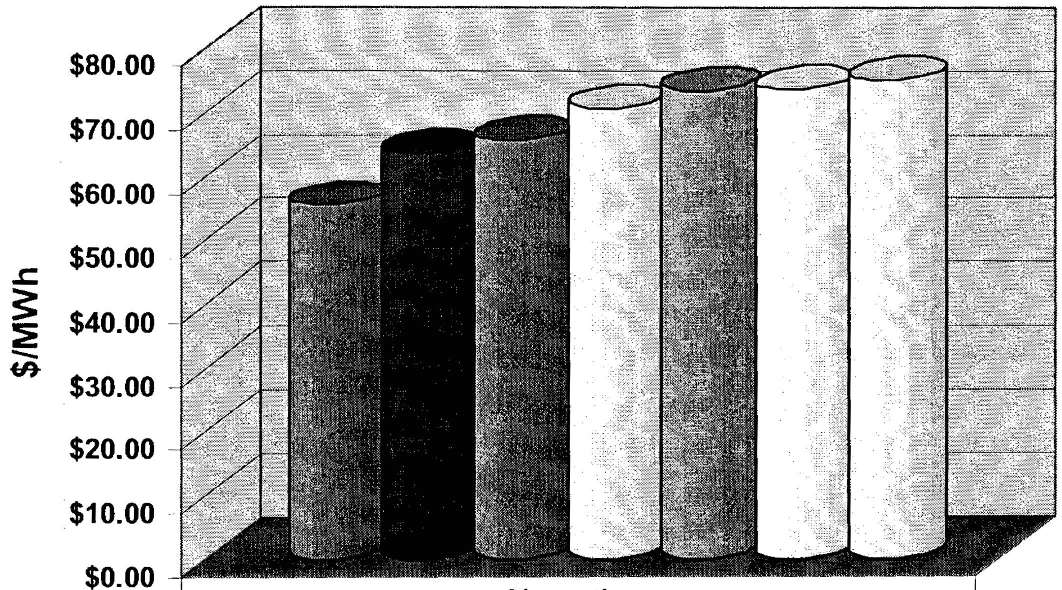
## 1.5 SUMMARY OF ENVIRONMENTAL PERMITTING ASSESSMENT

B&McD prepared a permit matrix and preliminary environmental permitting schedule for a proposed solid fuel generation resource to be sited and developed in Florida. The preliminary permit matrix lists each of the environmental permits anticipated to be required for the Project.

Appendix C contains the permit matrix and a preliminary environmental permit/clearance schedule. The application and approval of the Project's regulatory certificate and air permit will be the long lead permits to secure before construction of the Project can commence. Note that transmission line approvals/permits and regulatory approvals may also impact the implementation schedule in addition to the permits for the generating station if new transmission lines are required to support the facility.

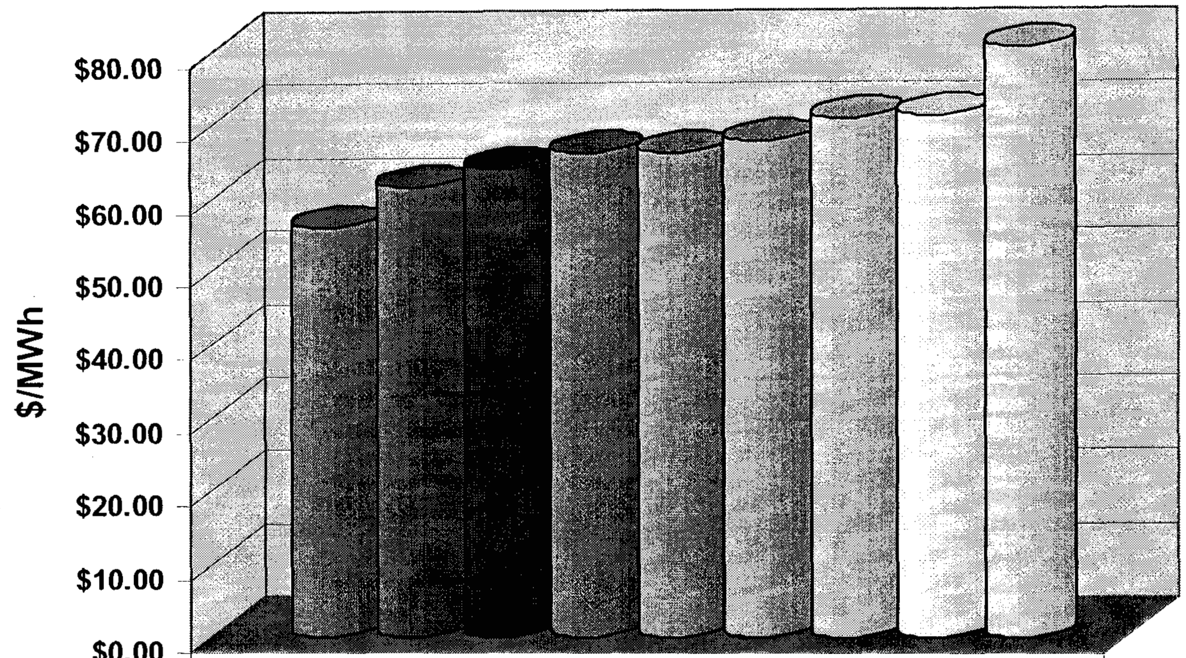
The permit schedule reflects an approximate 30 month period from the time preliminary engineering for permit preparation is initiated until the site certification is issued.

**Figure 1-2**
**Levelized 20 Year Busbar Costs**
**500 MW Greenfield PC Unit with Alternative Fuel Sources**



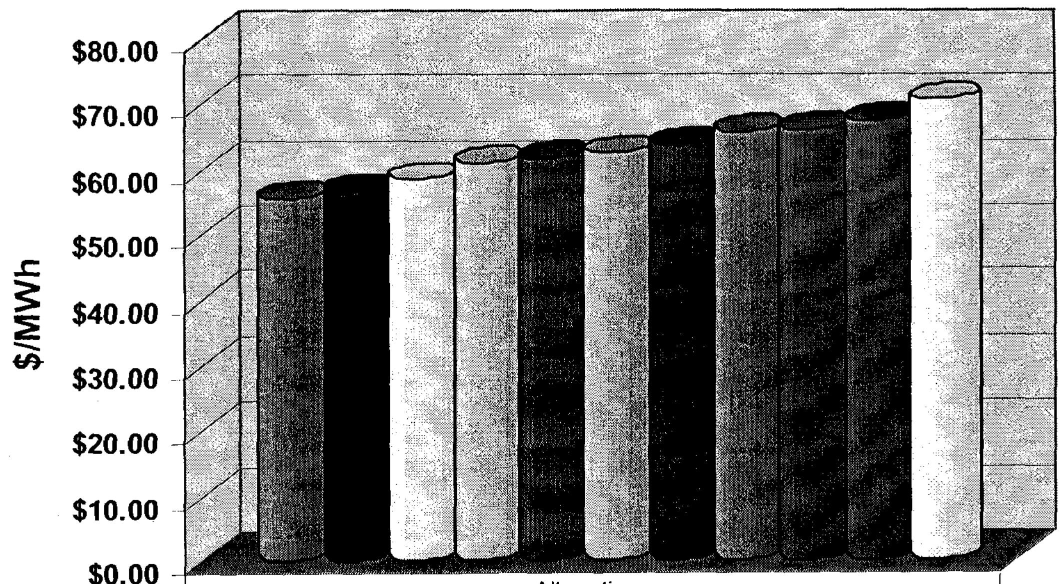

| | Alternatives |
|---|---|
| 500 CCGT NG RFP | $55.61 |
| 500 CCGT NG REF | $63.76 |
| 500 PC Sub IMPORT | $65.80 |
| 500 PC Sub ILB | $70.76 |
| 500 PC Sub PITT | $73.50 |
| 500 PC Sub CAPP | $73.79 |
| 500 PC Sub PRB | $75.06 |

## Figure 1-3
## Levelized 20 Year Busbar Costs
## 500 MW Greenfield Site with Alternative Technologies




| | Alternatives |
|---|---|
| 500 CCGT NG RFP | $55.61 |
| 500 CFB PETCOKE | $61.26 |
| 500 CCGT NG REF | $63.76 |
| 500 PC Sub IMPORT | $65.80 |
| 500 PC Super IMPORT | $65.79 |
| 500 CFB BLEND | $67.52 |
| 500 PC Super ILB | $70.66 |
| 500 PC Sub ILB | $70.76 |
| 500 IGCC ILB | $81.51 |

## Figure 1-4
## Levelized 20 Year Busbar Costs
## Overall Summary of Results




| | Alternatives |
|---|---|
| 500 CCGT NG RFP | $55.61 |
| 500 PC Sub IMPORT BRN | $56.87 |
| 500 CFB BLEND BRN | $58.58 |
| 750 PC Sub IMPORT | $61.04 |
| 500 PC Sub ILB BRN | $61.82 |
| 750 CFB BLEND | $62.58 |
| 500 CCGT NG REF | $63.76 |
| 500 PC Sub IMPORT | $65.80 |
| 750 PC Sub ILB | $66.27 |
| 500 CFB BLEND | $67.52 |
| 500 PC Sub ILB | $70.76 |

## 1.6 SUMMARY OF SITING CONSIDERATIONS

A specific site location for a potential solid fuel generation resource has not been identified as part of this feasibility study. However, B&McD has evaluated the general site requirements for a solid fuel plant located in Florida.

There are 32 existing coal generation units in Florida with a capacity greater than 100 MW. The majority of these units were brought online prior to 1990, and a number of the units are currently more than 30 years old. The most recent two units are the CFB units commissioned by Jacksonville Electric Authority at the Northside Station in 2002. The vast majority of plants are sited near rail lines or bulk unloading facilities, or both.

Some of the key factors that should be considered by Progress in siting a solid fuel generation resource should include:

- Control Area
- Fuel Delivery Infrastructure
- Transmission Infrastructure
- Urban Areas and Ozone Maintenance Areas
- Class I Areas
- Site Acreage Requirements
- Water Availability
- Brownfield Locations

Section 6 provides an initial assessment of the above factors. Figure 1-5 at the end of this section presents an overview map of Florida highlighting some of the siting attributes and constraints.

## 1.7 SCHEDULE ISSUES

A preliminary schedule for the design and construction of a 500 MW unit at a greenfield site location is included in Appendix E. The total design/construction/startup for the first unit of the Project is estimated to require 54 months from full notice to proceed and procurement release to commercial operations. Construction time in the field is estimated to require 48 months. This schedule does not include site specific schedule impacts for the construction of a transmission line, which will have to be further evaluated when a specific siting study is performed. The execution method identified in the schedule is an engineering, procurement, construction (EPC) structure under which a single entity is responsible for design, construction, and commissioning of the Project.

For planning purposes, the key milestone dates working backward from a January 2011 commercial operation date for a new solid fuel generation resource would be the following:

| | |
|---|---|
| • Commercial Operation | January 2011 |
| • Start Construction | February 2007 |
| • Receive Final CPCN/Air Permit Approval | February 2007 |
| • Full Notice to Proceed and Release Major Equipment | August 2006 |
| • Award EPC Contract and Limited Notice to Proceed | March 2006 |
| • Submit CPCN and Air Permit Applications | June 2005 |
| • Start EPC Contract Package Development/Bid | February 2005 |
| • Start Preliminary Engineering | February 2005 |
| • Issue RFP for Power Supply | July 2004 |
| • Initiate Siting Study | January 2004 |

The major development requirements to be completed prior to beginning preparation of the environmental permits and regulatory filings are to identify a candidate site(s), secure the site, and conduct a power supply RFP for baseload energy requirements pursuant to Rule 25-22.082 of the Florida Administrative Code. Rule 25-22.082 of the Florida Administrative Code requires investor-owned utilities to provide a description of the "next planned generating unit" on which the RFP is based. Progress is currently going through this process for the Hines Energy Complex Unit 4, located in Polk County, Florida.

A siting study to identify specific candidate site(s) locations should require approximately 4 to 6 months to complete. During the siting study, a conceptual engineering effort should be undertaken to refine the generic cost estimates presented in this study based on specific candidate site locations, potential fuel supply and delivery alternatives, and technology preferences. The conceptual engineering effort would also develop the RFP requirements needed to meet Rule 25-22.082 if a new solid fuel generation resource was the preferred alternative. Overall, the siting study and conceptual engineering effort, including management decisions to proceed with a solid fuel resource, will require 6 to 8 months.

The current power supply solicitation schedule for the Hines IV unit outlines a 13-month process, and it is reasonable to assume the power supply evaluation and solicitation process for a proposed baseload energy resource would require 12 to 18 months also.

Therefore, the schedule above indicates that a 2011 commercial operation date will likely require that Progress proceed with preliminary engineering, permitting, and EPC contract package development and bidding prior to completing the evaluation and negotiation of the power supply RFP results. Overall, the schedule is very aggressive to meet a targeted commercial operation date of January 2011. A more realistic planning timeframe that would allow full regulatory and management review would be to target a commercial operation date of January 2012 for a greenfield site. If a brownfield expansion site is available, a 2011 commercial operation date is more viable. While the construction schedule for a brownfield expansion would only be reduced by a few months, the development and permitting time frame can also be reduced by several months since an existing site is under control.

## 1.8 RECOMMENDATIONS

If Progress determines a solid fuel generation resource should be considered in Florida, Burns & McDonnell recommends that Progress proceed immediately with a siting study to identify specific candidate site(s) locations and a conceptual engineering effort to refine the generic cost estimates presented in this study based on specific candidate site locations, potential fuel supply and delivery alternatives, technology preferences, and environmental constraints. The conceptual engineering effort would also develop the RFP requirements needed to meet Rule 25-22.082 if a new solid fuel generation resource was the preferred alternative meeting energy requirements in the 2011-2030 planning period. Overall, the siting study and conceptual engineering effort, including management decisions to continue development of a solid fuel resource, will require 6 to 8 months. This effort should be initiated soon to maintain a potential 2011 online date for a new solid fuel generation resource.

The Feasibility Study is not intended to provide a definitive recommendation regarding the selection of a solid fuel generation resource in general, or a specific solid fuel generation technology and fuel supply in particular. Additional resource planning efforts should be prepared by Progress to evaluate the estimated costs and benefits of a wide variety of generation resource alternatives to meet its Florida load in a cost effective and reliable manner. This Feasibility Study provides planning level information on expected costs, performance, benefits, and risks of potential solid fuel generation alternatives to aid Progress in those resource evaluations. If further resource planning efforts identify a need for baseload energy and Progress management, in consultation with the regulatory agencies, determines that a solid fuel generation resource is one of preferred resource alternatives, this Feasibility Study also highlights the long lead time for planning and permitting that needs to be considered in adding a solid fuel generation resource to the system.

## 1.9 STATEMENT OF LIMITATIONS

In preparation of this Feasibility Study, Burns & McDonnell has made certain assumptions regarding future market conditions for construction and operation of solid fuel generation resources. While we believe the use of these assumptions is reasonable for the purposes of this Feasibility Study, B&McD makes no representations or warranties regarding future inflation, labor costs and availability, material supplies, equipment availability, weather, and site conditions. To the extent future actual conditions vary from the assumptions used herein, perhaps significantly, the estimated costs presented in the Feasibility Study may vary.

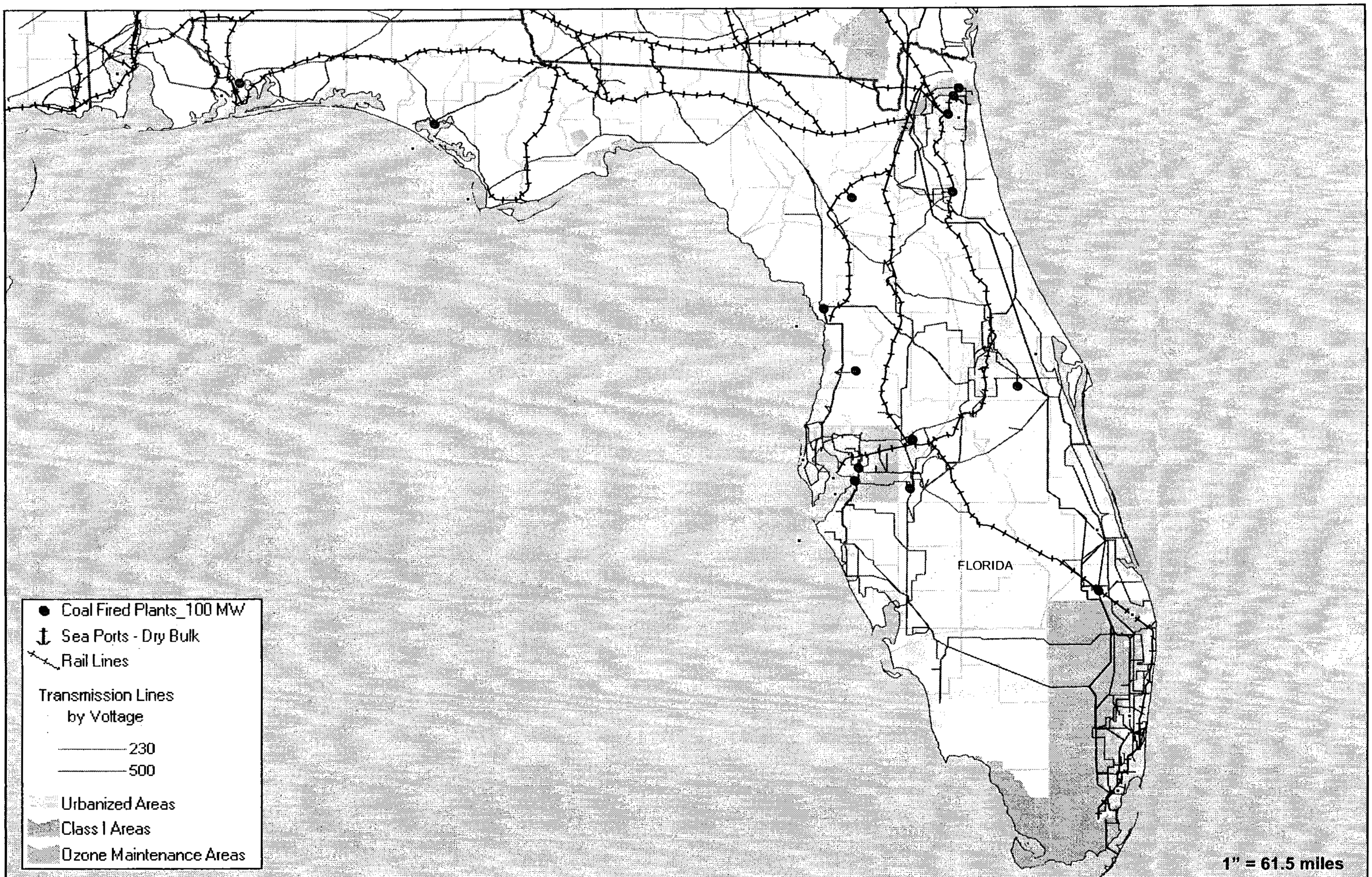



Figure 1-5

# Progress Energy

## Florida State Overview Map

Burns & McDonnell SINCE 1898

# Section 2

# Technology Assessment

# SECTION 2
# TECHNOLOGY ASSESSMENT

## 2.1 OBJECTIVE

The following technology assessment and cost estimates are provided for use by Progress in evaluating available technologies for application in a new solid fuel generation resource to be located in Florida.

## 2.2 TECHNOLOGY ASSESSMENT OVERVIEW

The assessment focuses on four primary types of power plant technologies:

- Subcritical Pulverized Coal (PC)
- Supercritical Pulverized Coal (PC)
- Circulating Fluidized Bed (CFB)
- Integrated Gasification Combined Cycle (IGCC)

These technologies are discussed based on advantages/disadvantages, expected capital cost differentials, expected performance differences, operating considerations and costs, environmental issues and industry trends for a 500 MW, 750 MW, and 1000 MW PC and CFB plant sizes and also for a 500 MW IGCC plant.

Each technology has a "Base Case" that provides a reference point for the evaluations. The base case alternatives are provided in Appendix A. Within each technology, the following alternatives and issues were also evaluated:

- Greenfield versus brownfield site location
- Coastal versus inland site location
- Wet versus dry cooling systems
- Wet versus dry flue gas desulfurization (FGD)
- Zero Liquid Discharge (ZLD) system
- Alternative design coals (PRB, Eastern Bituminous, Imported Coal, Pet Coke)

The impact of these options and results are also provided in Appendix A and are expressed in terms of differentials (cost, heat rate, etc.) from the Base Case estimates.

The 500 MW PC units and 750 MW PC units each consist of a single boiler and a single steam turbine. Although a 1000 MW PC unit comprised of one boiler and one steam turbine is possible for a supercritical unit, it would require two parallel steam drums for a subcritical unit. In addition, there is significantly more operating history with 500 MW PC units and a large single generator can be problematic for the transmission system. Therefore, the 1000 MW PC units evaluated are comprised of two 500 MW blocks for both the subcritical and supercritical technologies.

Due to current size limitations of CFB boilers, the 500 MW CFB plant consists of two boilers and one steam turbine. The 750 MW CFB plant consists of 3 boilers and one steam turbine. The 1000 MW CFB unit consists of two 500 MW blocks (four boilers and two steam turbines). CFB boilers larger than 300 MW have been proposed and are currently being designed. However, there are no such units currently in operation.

Each of the combustion technologies is reviewed in further detail below.

## 2.3 PULVERIZED COAL TECHNOLOGY

Conventional pulverized coal (PC) technology is a reliable energy producer around the world. PC technology can be divided into two distinct designs which are distinguished by the maximum operating pressure of the cycle. The operating pressure of conventional coal-fired power plants can be classified as subcritical and supercritical. Subcritical and supercritical technology refers to the state of the water that is used in the steam generation process. The critical point of water is 3,208.2 psi and 705.47°F. At this critical point, there is no difference in the density of water and steam. At pressures above 3,208.2 psi, heat addition no longer results in the typical boiling process in which there is an exact division between steam and water. The fluid becomes a composite mixture throughout the heating process.

Subcritical power plants utilize pressures below the critical point of water, whereas supercritical power plants utilize pressures above the critical point of water.

### 2.3.1 Subcritical

The majority of the steam generators built in the United States utilize subcritical technology. These units utilize a steam drum and internal separators to separate the steam from the water.

In general, the steam cycle consists of one steam generator and one steam turbine generator. The balance of plant equipment consists of a condenser, condensate pumps, low-pressure feedwater heaters, deaerating feedwater heater, boiler feedwater pumps and high-pressure feedwater heaters.

In the steam generator, high-pressure steam is generated for throttle steam to the steam turbine. The steam conditions are typically 2400 - 2520 psig and 1000°F-1050°F at the steam turbine. The steam expansion provides the energy required by the steam turbine generator to produce electricity.

The steam turbine exhausts to a condenser where the steam is condensed. The heat load of the condenser is typically transferred to a wet cooling tower system. The condensed steam is then returned to the steam generator through the condensate pumps, low-pressure feedwater heaters, deaerating heater, boiler feed pumps and high-pressure feedwater heaters.

Most subcritical units utilize a deaerating feedwater heater as the last low-pressure feedwater heater before the boiler feedwater pumps. This helps remove oxygen from the feedwater before entering the steam generator. Some operating units utilize a closed feedwater system in lieu of a deaerating feedwater heater. Typically in these units, a deaerating condenser is included in the system.

Coal is supplied to the unit through coal bunkers, then to the feeders and into the pulverizers where the coal is crushed into fine particles. The primary air system transfers the coal from the pulverizers to the steam generator burners for combustion.

Flue gas is transferred from the steam generator, through a selective catalytic reducer (SCR) for $NO_x$ reduction and into an air heater. For a plant with a dry scrubber, flue gas flows from the air heater to a scrubber system and then to a particulate removal system. For a plant with a wet scrubber, it flows to the particulate removal system and then to then scrubber system.

**2.3.1.1 Performance:** 500 MW subcritical pulverized coal units are very common in the United States. Much of the data gathered indicates that the starting time of these units range from 4 to 5 hours. This is largely due to the limitation of temperature ramp rates to minimize thermal stresses in the steam drum.

Operational heat rates for subcritical PC units are estimated at 9,377 Btu/kWh (HHV) for a 750 MW size unit utilizing steam conditions of 2520 psig and 1050°F/1050°F.

**2.3.1.2 Emissions:** $NO_x$ emissions of a PC unit are controlled with Selective Catalytic Reduction (SCR). A SCR system installed in a PC unit burning PRB coal can reduce the $NO_x$ emissions to approximately 0.08-0.10 lb/MMBtu or below, although there is not significant operating history. For this study, the $NO_x$ emissions for the PC units were targeted at 0.07 lb/MMBtu to meet expected Best Available Control Technology (BACT) requirements in Florida. Further discussions of BACT requirements in Florida are included in Section 5 of this report. The table in Appendix B presents the expected BACT requirements and selected control technologies for the different fuels and combustion technologies under evaluation.

$SO_2$ control is accomplished through the use of either a dry or wet flue gas desulfurization (FGD) system. Refer to Section 2.5 for discussion of wet versus dry FGD systems. A dry FGD system can achieve approximately 92% to 93% removal and a wet FGD system can achieve approximately 95% to 98% removal.

The industry is currently testing mercury control technology. The expected method of removal for units with a dry FGD system is fly ash or activated carbon reinjection. A reagent injection system is currently under development for units with a wet FGD system.

The current industry trend for emission control on a subcritical PC unit burning a low sulfur fuel is to include a SCR, a dry FGD system and a pulse jet baghouse, which is the basis of the base case PC Unit estimates in Appendix A.

**2.3.1.3 Waste Disposal:** The byproducts from this combustion process and flue gas cleaning process are fly ash and gypsum (only if a specific type of wet FGD system is used). The fly ash produced as a byproduct can be utilized as structural fill for developing new roads, or for a wet scrubber, can be used to supplement cement. The gypsum produced by a wet FGD system can be used for making wall board.

A site market analysis would be required to determine potential markets for this waste. Even if the flyash and gypsum are sold with zero profit, substantial savings can be made because these products do not have to be landfilled. If a suitable market can not be found, then waste disposal will be required. For purposes of this study, the base case uses a dry scrubber system and assumes landfilling of the flyash. The O&M cost of on-site waste landfilling is estimated at $5.30/ton and includes hauling, labor, and development of additional landfill cells in the future. The initial cost for a five year landfill cell is included in the capital cost of the Project.

A wet scrubber was also evaluated that allows the flyash and gypsum to be separated and sold to market. The O&M analyses for the "flyash/gypsum sales option" in Appendix A assume no profit from the sale of gypsum and flyash, however, it is assumed that these products are essentially given away, thus avoiding the landfilling costs of this material.

**2.3.1.4 Capital Cost Estimates:** Total Project capital costs for a 750 MW block consisting of 1 x 750 MW subcritical pulverized coal plant utilizing a dry FGD system and a pulse jet baghouse is estimated at $1377/kW (2010$) for a greenfield site. The scope of this estimate is defined in Section 2.6.

**2.3.1.5 Operations and Maintenance Estimates:** The estimated fixed O&M of a 750 MW PC unit is $17.60/kW-yr. This includes operations and maintenance labor, office & administration, training, contract labor, safety, building and ground maintenance, communication and laboratory expenses and start-up power demand. Property taxes and insurance are not included.

The estimated Non-Fuel Variable O&M of a 750 MW PC unit is $2.76/MWh. The variable O&M estimate includes the following items: makeup water, water disposal, lime (assuming a dry FGD system), ammonia, SCR replacements, ash disposal, spare parts and equipment, major maintenance, and other consumables not including fuel.

### 2.3.2 Supercritical

Supercritical boilers have been incorporated into the United Stated power generation mix since the mid 1950's. There are over 80GW of supercritical units in the U.S., with the majority of units coming online before 1980. At the same time, several new nuclear power plants were constructed for base load capacity. Therefore, the supercritical plants were required to follow the utility load. Due to a lack of high temperature materials, the existing materials were required to be fairly thick to withstand the operating conditions. The result was excessive valve wear, turbine thermal stresses and turbine blade solid particle erosion. This resulted in lower availability and higher maintenance costs than comparable subcritical units.

Since the start of the 1980s, the majority of supercritical units have been installed in Europe and Asia. The development of high strength materials has helped to minimize the thermal stresses that caused problems in the early units. The development of Distributed Control Systems (DCS) has helped make a complex starting sequence much easier to control and minimize tube overheating due to lack of fluid. The newer units also use a particle separator placed into the fluid process which allows recirculation of excess waterwall outlet fluid back to the waterwall inlet for loads below 35% MCR. Below that load, the unit is controlled similar to a drum type boiler, and a water level is maintained in the separator tank at the waterwall outlet, and feedwater flow to the unit is controlled to hold that water level. Below that load, the final steam temperature is controlled by spray water in the superheater attemperators. To ensure a minimum flow of 35% MCR water flow always flows through the waterwall for all low loads, some water needs to be recirculated back to the waterwalls. Above 35% MCR load, the unit becomes "once through" and the feedwater flow is controlled through the ratio of firing rate to feedwater flow in order to hold a final high pressure (HP) main steam temperature setpoint.

Solid particle carryover to modern full arc throttling steam turbines has been reduced by the implementation of HP bypasses. All exfoliated solids from the oxidation of the superheaters is spalled off during first fires and is dumped into the reheater and then to the condenser, bypassing the HP turbine's first stage and thus protecting the steam turbine. Therefore, many of the early problems with the units have been corrected.

The general description of the supercritical units is very similar to that of the subcritical units described earlier. The major difference is that the steam generator is a once through system and does not include a steam drum. Also, the feedwater system includes all closed feedwater heaters and typically does not include a deaerating heater.

Since there is no steam drum to allow blowdown of impurities in the system, water chemistry is critical to maintain a reliable system. A condensate polisher is typically incorporated into the condensate system to clean the condensate of impurities.

Many of the plants are also implementing an oxygenated water treatment system into their operation. An oxygenated water treatment system forms a ferric oxide hydrate on the inner surface of the steam generator. The traditional volatile system forms a magnetite oxide in the system. The advantage is that the ferric oxide is much less soluble; therefore the quantity of the oxide transported to the steam turbine is reduced.

A non-technical factor for Owners considering a supercritical unit is the availability of experienced operators. The average power plant employee is 48 years old. Unless an Owner currently has experienced supercritical operators, obtaining them may not be easy. Therefore, new operators would need to be trained on a system that is complex.

Supercritical units are provided with essentially two types of tube arrangements: spiral or vertical. The spiral tube design has more than 30 years of experience. The primary disadvantage is the hardware needed to support the tubes during construction causes increased construction efforts. The spiral tube design also imparts additional friction drop in the system requiring larger boiler feedwater pumps. The vertical tube design has a much shorter history, but is gaining interest due to the reduced pressure drop and simpler configuration.

Below about 500 MW, all modern, variable pressure, once through units will need to employ a spiral wound furnace waterwall. Above about 500 MW, there is a possibility that the furnace waterwall can utilize a new design of a vertical rifled tube. The spiral wound design is more difficult to fabricate, install, and repair and collects more slag than a vertical tubed furnace and also has a higher pressure drop. The vertical rifled tube design has a much lower pressure drop and is easier to fabricate, construct, and repair but has only been used on one coal fired furnace to date.

Most of the units built in the past twenty years in Europe and Asia have been the more efficient supercritical units due to the higher delivered cost of solid fuel in these areas. Supercritical units are also less sensitive to fuel variability than subcritical units, allowing the purchase of coal on the international spot market. A subcritical boiler has a limited range of fuels it can fire, due to the fact that each coal will affect the relative heat absorption rate in the furnace waterwalls and superheaters. For a subcritical unit, this affects the ability to achieve design final steam temperature and spray quantities. A supercritical unit, on the other hand, can always achieve design final steam temperature for all loads above 35% MCR simply by varying the ratio of firing rate to feedwater flow. This assumes the coal purchased can be processed by the mills, and be burned in the furnace without excessive slagging.

**2.3.2.1 Performance:** Supercritical units typically operate at 3500 psig and at 1000°F or 1050°F. For purposes of this evaluation, a 1050°F main steam and reheat temperature is used. Development is currently underway to increase the pressures to 4350 psig and the temperatures to 1112°F. These are considered ultracritical units and are considered unproven technology.

The conventional supercritical units provide an increased efficiency of approximately 2.8% over that of a subcritical unit with the same steam temperatures. Supercritical units are also more efficient at partial loads. For example, at 75% load, the efficiency of a supercritical unit is reduced by 2% compared to 4% for a subcritical unit. At 50% load, the efficiency of a supercritical unit is reduced by 6-8% compared to 10-11% for a subcritical unit.

In a supercritical unit, the auxiliary power (or steam energy) input is substantially higher to the feedwater system compared to a subcritical unit. In a supercritical unit, the boiler feed pumps require about twice as much energy as that of a subcritical unit. However, the increase is justified by the improved thermal cycle efficiency.

The typical heat rate of a 750 MW supercritical PC with process conditions of 3500 psig and 1050°F is approximately 9,115 Btu/kW (HHV) with availability equal to the similar subcritical unit and start up times that range from 3 to 3.75 hours.

**2.3.2.2 Emissions:** The emission controls for $NO_x$, $SO_2$ and mercury are similar to that discussed for the similar subcritical unit. The advantage is that the improved efficiency of the unit reduces the amount of fuel consumed and gasses exhausted, which reduces the total emissions.

**2.3.2.3 Waste Disposal:** The waste disposal issues are identical to the issues discussed for the similar subcritical unit.

**2.3.2.4 Capital Cost Estimates:** Total capital cost for a 750 MW block consisting of 1x750 MW supercritical pulverized coal plant utilizing a dry FGD system and a pulse jet baghouse is estimated at $1,402/kW (2010$) for a greenfield site. This is an increase of approximately 1.8% over a similar subcritical unit. The increased costs are in the boiler, steam turbine, boiler feedwater pumps, feedwater heaters, and piping. The scope of this estimate is outlined in Section 2.6.

**2.3.2.5 Operations and Maintenance Estimates:** The fixed O&M costs for a supercritical unit are essentially the same as for a similar subcritical unit. Variable O&M Costs are slightly lower due to reduced lime, ammonia, and water consumption (due to the increased efficiency of the cycle). This results in a variable O&M of approximately $2.71/MWh, a savings of approximately $0.05/MWh compared to a subcritical unit of the same size.

## 2.4 CIRCULATING FLUIDIZED BED TECHNOLOGY

The combustion process within a fluidized bed boiler occurs in a suspended bed of solid particles (usually limestone and ash) in the lower section of the boiler. These solid particles act as the ignition source for the fuel. Therefore, the fuel is utilized in larger particles, with a slower combustion rate and at a lower temperature than a conventional pulverized coal boiler. Deviations in fuel type, size or Btu content has minimal effect on the furnace performance characteristics. The bed also allows for reinjection of a sorbent, such as fly ash or limestone, to reduce emission levels.

Fluidized bed technology has historically been characterized as a clean coal technology. This perception is being challenged in many areas of the country by BACT requirements. Achieving emission levels meeting these requirements include addition of SNCR systems for $NO_x$ control and a fly ash and/or limestone reinjection system for $SO_2$ control. The reinjection system adds to the complexity of material handling systems. Installations that burn high sulfur fuels or require higher removal efficiencies may require an additional dry scrubber (polishing scrubber) for the flue gas.

This technology is well suited to burn fuels with large variability in constituents. Plant sites with access to an abundant source of fuel that presents combustion challenges in a pulverized coal boiler are typically good prospects for application of fluidized bed technology. In addition, CFB units offer more fuel flexibility compared to PC technology which can be beneficial to keep long-term fuel costs down. The following are plant characteristics of fluidized bed technology and issues considered during the technology selection phase.

### 2.4.1 Performance

The largest fluidized bed boilers in operation are approximately 250 MW (net) with two 300 MW (gross) units recently commissioned in Jacksonville, Florida. Since individual boiler units larger than 250 MW may encounter maintenance and operational issues associated with prototype development, the most economical configuration utilizing proven technology is 2 x 250 MW boiler units supplying steam to a single steam turbine.

Most manufacturers of CFB's use thick refractory in the cyclones, which require a slow component startup rate and results in long time periods for which the CFB is emitting higher levels of $NO_x$. One manufacturer avoids this by using a steam cooled cyclone with thin refractory and faster startups. Cold start-up times for a fluidized bed boiler are commonly in 12-14 hour range compared to a conventional subcritical PC boiler start-up time of 4-5 hours. Capability for load following is also reduced compared to a conventional PC boiler due to limitations in thermal change rates of the very thick refractory utilized in the bed section of a fluidized bed boiler. This limitation would present a significant challenge to a large power facility operating one or more units in load following operation.

Operational heat rate performance for fluidized bed units is estimated at 9,914 Btu/kWh (HHV) for a 750 MW configuration.

### 2.4.2 Emissions

For a CFB boiler, a Selective Non-Catalytic Reduction (SNCR) system is typically utilized to limit $NO_x$ emissions level to around 0.10-0.15 lb/MMBtu. This is accomplished by injecting ammonia or urea into the gas path. For this project, a $NO_x$ emission level of 0.07 lb/MMBtu is used to meet expected Best Available Control Technology (BACT) requirements in Florida. The table in Appendix B presents the expected BACT requirements and selected control technologies for the different fuels and combustion technologies under evaluation.

$SO_2$ control is usually accomplished through injection of limestone and potential reinjection of flyash into the furnace. Limestone injection typically achieves a 95% $SO_2$ removal rate. The limestone acts as the circulating medium for fuel ignition as well as provides calcium for reaction with sulfur to remove $SO_2$. Hydrated flyash reinjection can be utilized to reduce limestone consumption. $SO_2$ control in a fluidized bed boiler requires approximately 1.5 times the quantity of limestone to achieve a similar reduction level to that achieved in a PC unit with a wet scrubber.

### 2.4.3 Waste Disposal

Fluidized bed boilers produce a waste product that is a combination of ash, limestone and calcium sulfate. Generally, the only suitable byproduct sales are for structural fill or road bed material. A site market analysis would be required to determine potential markets for this waste. If a suitable market can not be found, then waste disposal will be required. For purposes of this study, on-site waste landfilling is factored into the initial capital costs and O&M costs for the facility.

### 2.4.4 Capital Cost Estimates

Total project capital costs for a 750 MW block consisting of 3 x 250 MW fluidized bed boilers utilizing common steam turbine and auxiliary systems would be approximately $1,454/kW (2010$) for a greenfield site.

### 2.4.5 Operations & Maintenance Estimates

With respect to O&M expenses, three CFB units require more staff to operate and maintain the plant than a single PC unit at 750 MW. The estimated O&M expenses for a 750 MW CFB unit are $19.95/kW-yr fixed and $2.60/MWh variable, respectively.

## 2.5 INTEGRATED GASIFICATION COMBINED CYCLE TECHNOLOGY

### 2.5.1 Description

Integrated Gasification Combined Cycle (IGCC) technology produces a low calorific value syngas from coal or solid waste to be fired in a combined cycle or utility boiler. The gasification process represents a link between solid fossil fuels such as coal and existing gas turbine technology.

### 2.5.2 Technology

Integrating proven gasifier technology with proven combustion turbine combined cycle technology has been quite successful in applications utilizing fuels such as petroleum coke, asphalt, visbreaker tar, fluid coke, cracked tar, and heavy residual oil. Utilizing coal as the primary feedstock has been less successful and the technology continues to be improved at the DOE jointly funded power plants.

Gasifiers designed to accept coal as a solid fuel fall into three categories: entrained flow, fluidized bed, and moving bed.

**Entrained Flow**

The entrained flow gasifier reactor design is based on coal conversion into molten slag. This gasifier design utilizes high temperatures with short residence time and will accept either liquid or solid fuel. Texaco, Destec, Prenflo, and Shell produce gasifiers of this design.

**Fluidized Bed**

Fluidized bed gasifiers accept a wide range of solid fuels, but are not suitable for liquid fuels. The KRW, MBEL, and High Temperature Winkler designs are based on this technology.

**Moving Bed**

Moving bed gasifiers are also not suitable for liquid fuels. The Lurgi Dry Ash gasification process is a moving bed design and has been utilized both at the Dakota Gasification plant for production of SNG and the South Africa Sasol plant for production of liquid fuels. A gasifier manufactured by BGL is also a moving bed design.

The entrained flow gasification design has been utilized at the majority of the DOE test facilities that utilize coal as feedstock. Pulverized coal is fed in conjunction with oxygen from an air separation unit (ASU) and steam into the gasifier at around 450 psig to chemically react. The raw fuel gas produced by the reaction in the gasifier exits at around 2400 °F and is cooled to less than 400 °F in a gas cooler, which produces additional steam for both the steam turbine and gasifier process. Scrubbers then remove particulate, ammonia ($NH_3$), hydrogen chloride and sulfur from the raw syngas stream. The cooled syngas is then fed into a modified combustion chamber of a combustion turbine specifically designed to accept the low calorific syngas. Excess heat from the combustion turbine is recovered in a Heat Recovery Steam Generator (HRSG). Reliability issues associated with fouling within the syngas cooler have challenged the existing gasifier designs. The syngas cooler greatly improves thermal efficiencies when compared to a quench cooler system typical to those utilized in chemical production gasifiers.

### 2.5.3 Current Status

The following are the four DOE jointly funded test facilities that have been constructed in the United States, with various gasification system designs.

*Plaquemine*, 160 MW, 1987 start-up, Destec gasifier
*Wabash River*, 262 MW, 1995 start-up, Destec gasifier
*Polk County*, 250 MW, 1996 start-up, Texaco gasifier
*Pinon Pine*, 99 MW, 1997 start-up, KRW gasifier

All of these projects have experienced significant challenges in achieving reliable commercial operation. The next DOE funded facility in development is a 540 MW power station with Kentucky Pioneer Energy.

### 2.5.4 Plant Characteristics

**2.5.4.1 Performance:** Cold start-up times for IGCC plants have typically ranged from 40-50 hours compared to a conventional PC boiler start-up time of 4-5 hours. Hot restart procedures are in testing at several of these facilities, but the technology to support load following remains to be developed.

Operational heat rate (HHV) performance for these test facilities ranges from 7,800 Btu/kWh (43.7% efficiency) for Pinon Pine to 8,910 Btu/kWh (38.3% efficiency) for Wabash River. The Polk County facility operated at around 8,500 Btu/kWh (40.2% efficiency), but modifications to improve gas clean-up reliability reduced efficiency and increased heat rate for the plant to around 9,350 Btu/kWh (36.5% efficiency).

Unit availability at the DOE jointly funded plants has been greatly reduced due to significant design modifications required to improve equipment life and reliability. Polk County was able to achieve 83% availability over one six-month period and Wabash River achieved 79.1% availability in 1999, but overall availability is much less since initial plant start-up. All of these coal gasifier plants have experienced excessive down-time for design modifications and replacement of numerous systems. Wabash River recently added an auxiliary boiler to improve availability of their steam turbine output. Polk County and Wabash River are the only two coal gasifier plants in the United States that have achieved extended periods of commercial operation.

**2.5.4.2 Emission Controls:** Raw syngas produced by the IGCC process is cleaned to remove particulate, ammonia ($NH_3$), sulfur and nitrogen prior to being fired in the gas turbine. Removal of pollutants from the syngas steam results in significantly lower emissions than from a conventional plant utilizing the same fuels.

Sulfur capture for coal gasifiers at the DOE funded power plants ranged from >95% (Polk County) to >99% (Wabash River). $NO_x$ emissions were controlled though nitrogen injection at Polk County to 0.10 lb/MMBtu (25 ppm) and through steam injection at Wabash County to 0.10 lb/MMBtu. However, Wabash did not go through Prevention of Significant Deterioration (PSD) permitting for $NO_x$. Polk County was required to reopen their $NO_x$ BACT 18 months after startup of the facility. The draft $NO_x$ BACT now requires SCR for $NO_x$ control to 5 ppm. Polk County is currently challenging the SCR requirement in court. The June 2001 permit for Kentucky Pioneer required 15 ppm $NO_x$ using diluent injection with a provision to reopen the $NO_x$ BACT 18 months after startup.

**2.5.4.3 Waste Disposal:** The syngas sulfur removal process results in 99.99% pure sulfur, which is a valuable by-product. Coal ash is converted in the gasifier to a low-carbon vitreous slag. This slag can be utilized as grit for abrasives and roofing materials or as an aggregate in construction.

**2.5.4.4 Capital Cost Estimates:** Initial capital construction cost (in 1995 dollars) for these coal gasification plants ranged from $1,213/kW for Polk County, $1,590/kW for Wabash River and up to $4,890/kW for the other facilities. Polk County, Wabash River and Pinon Pine continue to invest significant additional capital expenditure to upgrade equipment to improve plant availability.

DOE estimates coal-based IGCC plants in the range of $1,200-1,400/KW for a 500 MW plant design operating at 44% percent efficiency (LHV). These estimates appear optimistic based on continuing development costs required for design modification at all existing coal IGCC facilities. Replacing the syngas cooler with a quench system would reduce cycle efficiency by 4.5-6% and reduce capital cost by approximately $200/kW. Any capital cost savings would be offset over the life of the plant by additional fuel costs associated with reduction in plant efficiency.

A total project cost estimate of $1,800/kW (2010$) is reflected in the study as a reasonable estimate until the next generation of IGCC units are demonstrated at a lower capital cost.

**2.5.4.5 Operation & Maintenance Estimates:** The O&M expenses for a 500 MW IGCC unit are estimated to be $23.60/kW-yr fixed and $3.35/MWh variable. Note that there has not been a long operating history for IGCC units.

### 2.5.5 Commercialization of IGCC Technology

**2.5.5.1 Market Trends:** The Texaco gasification system appears to be the current international IGCC market leader with over 40% of installed capacity. The next proposed Texaco coal gasifier installation is a 400 MW unit currently proposed for Killingley Colliery in England. The future development of coal gasification technology may occur in Europe or Japan if DOE does not fund additional development in the United States.

**2.5.5.2 Barriers to Commercialization:** Significant design issues have limited coal gasification units from achieving acceptable availability levels. Some of the design issues include fouling within the syngas cooler, design of the pressurized coal feeding system, molten slag removal from the pressurized gasifier, durability of gas clean-up equipment and solid particulate carryover resulting in erosion within the combustion turbine. The complexity of the combined cycle unit in conjunction with the reliability of numerous systems including the gasifier, $O_2$ generator, air separation unit and multiple scrubbers lends towards reduced plant availability. The current generation of IGCC plants should be capable of operation at availability of around 75% compared to around 90% for conventional plants.

Much of future technology development will be supported through government funding support of clean coal technology within the power industry. Operational flexibility for rapid start-up and load following remains to be demonstrated and may be required for an IGCC plant to compete effectively within the current U.S. power market.

**2.5.5.3 Long Term Development:** IGCC projects in the U.S. have been plagued with technical difficulties and an additional generation of units incorporating cost reduction strategies will be required prior to U.S. commercial implementation. The DOE has not yet defined additional projects that will complete development of technology required to support their current goal of $1,000/kW capital cost for IGCC plants utilizing a coal feedstock by 2008. Based on challenges encountered in the coal gasifier units, additional development may refocus on utilization of waste liquids, pet coke and other solid fuels that have demonstrated superior performance compared to coal. There are IGCC technology suppliers that are claiming higher reliability, lower capital costs, and lower operating costs. However, such characteristics have not been demonstrated in utility plants constructed to date. The current DOE Vision 21 Program provides joint project funding for integrating fuel cells into the IGCC cycle to achieve in excess of 50% overall plant efficiency.

Acceptance of coal within the power industry and the relative price of natural gas will also influence the future development and commercialization of IGCC in the United States. The technical barriers to commercialization still remain to be addressed through future generations of government jointly funded coal IGCC facilities. Once the development effort has been successfully completed, coal fueled IGCC technology appears to have the potential to be the long-term future for clean-coal generation within the United States.

## 2.6 WET FGD VERSUS DRY FGD

A variety of flue gas desulfurization (FGD) systems have been utilized to control $SO_2$ emissions from pulverized coal-fired power plants. Generally, these can be classified as either dry or wet FGD systems.

### 2.6.1 Dry FGD

In a dry FGD system, $SO_2$ is removed by contacting the flue gas with alkaline slurry. The quantity of slurry addition is carefully controlled so the absorber outlet gas temperature remains above saturation temperature, typically by 20-50°F. The particulate control device, located downstream of the dry absorbers, collects the absorber products along with flyash. Most dry FGD installations use fabric filters for particulate collection. The ash holdup on the bags contributes to the overall $SO_2$ removal.

Lime is the most common source of alkali used in dry FGD systems. If the fuel fired at the facility has a high alkaline ash, such as Powder River Basin (PRB) coal, ash collected by the fabric filter can be slurried and recycled to the absorber. Recycling the ash provides additional alkali to the absorber reducing the lime make-up requirements.

Several absorber designs have been used for dry FGD systems. The most common design for large, pulverized-coal units uses rotary atomization to insure good contact between the flue gas and the slurry. Alternate designs include dual-fluid nozzle atomizers and circulating fluidized bed absorbers. These designs are more commonly applied to smaller units. The evaluations in this report assume the installation of a lime spray dryer (LSD) system using rotary atomizers.

### 2.6.2 Wet FGD

In wet FGD systems, alkaline slurry is sprayed into the flue gas in an absorber module to saturate the flue gas and remove $SO_2$. In most wet FGD systems the slurry drains into a reaction tank from which it is recirculated back to the absorber module. Fresh alkali is made up to the reaction tank. A bleed stream from the reaction tank is processed to make the absorber products suitable for disposal.

Wet FGD system designs vary significantly. The primary factor that influences the design is the type of reagent. Reagents available for wet FGD systems include limestone, promoted limestone, lime, magnesium lime, fly ash, soda ash or ammonia. Limestone and magnesium promoted lime are the most common types of wet FGD systems that have been installed in recent years. Units firing lower sulfur coals normally use limestone for the reagent. Typically, limestone FGD systems include forced oxidation to produce gypsum. The evaluations in this report assume the wet FGD system will be limestone with forced oxidation (LSFO).

In recent years, the selection of the FGD process type for new coal-fired boilers has been dominated by "dry scrubbers". During the same period, FGD system retrofits to existing boilers for compliance with Phase I and Phase II of the Clean Air Act Acid Rain Control Program utilized wet FGD processes in every case. The difference in the selection of FGD process can be attributed to the sulfur content of the fuel fired at the facility. Most new facilities were designed to fire low-sulfur coals. The facilities that fire higher sulfur coals have typically retrofitted their FGD systems to meet the acid rain program requirements.

The capital costs for a dry FGD system will be lower than for a wet FGD system. Limestone, however, is less expensive than lime. Consequently, a LSFO wet FGD system will frequently have lower operating costs than a LSD system. This is particularly true when a unit fires high-sulfur coal.

### 2.6.3 Performance

The $SO_2$ removal capability of a dry FGD system is limited by the amount of contact time between the alkali and the flue gas and the gas temperature. Achieving high removal efficiencies with a dry system requires a close approach to the saturation temperature and higher reagent stoichiometry. Dry FGD systems are capable of sulfur dioxide removal efficiencies up to the mid-90s when treating flue gas from lower sulfur fuels. This generally results in emissions around 0.10 lbs/MMBtu.

Wet FGD systems typically have greater sulfur dioxide removal capability than dry FGD systems. On low sulfur fuels, wet FGD systems can achieve removal efficiencies of 95% or more. A wet FGD system installed on a unit firing low-sulfur coal should be able to achieve $SO_2$ emissions below 0.10 lbs/MMBtu.

### 2.6.4 Waste Disposal

One of the most important factors to consider in evaluating wet versus dry FGD systems is waste disposal and the marketability of the combustion products. In recent years, many utilities have actively marketed their combustion products with considerable success. If the combustion products are sold, substantial savings can be realized even if little or no money is received for the combustion products. This is because landfill costs are avoided.

Disposal of combustion wastes is a major drawback to dry FGD. In a dry FGD system, absorber products are collected along with the flyash in fabric filters or precipitators located downstream of the FGD system. The absorber product/flyash mixture is generally not salable. Consequently, the absorber product/flyash waste from a dry FGD system usually must be landfilled.

The situation is substantially different for a LSFO wet FGD system. Flyash is collected upstream of the FGD system and is not contaminated by the absorber products. Consequently, the flyash may be sold if a market is available in the plant vicinity.

A LSFO wet FGD system produces gypsum. The use of FGD byproduct gypsum has become generally accepted by the U.S. wallboard industry. In fact, forced oxidation has been retrofitted to a number of existing FGD systems in recent years to produce gypsum for wallboard production. FGD gypsum has also been used by the cement industry and for agricultural uses in recent years.

The marketability of the combustion products will depend on the facility's location. Generally, the closer a unit is located to urban areas, the more likely a market can be found for the combustion products. If a plant is located in a cold weather area, the marketability of the combustion products can be impacted. This is particularly true for flyash, which is commonly used by the construction industry. In cold climates, construction activity can be drastically reduced for several months out of the year reducing the potential for flyash sales.

### 2.6.5 Capital Cost Estimates

The capital costs of a wet and dry flue gas desulfurization (FGD) systems include the reagent feed system, $SO_2$ removal system, flue gas handling system, waste/byproduct handling system, and support equipment. In order to compare wet and dry FGD systems, capital costs were estimated to install lime spray dryers and wet limestone FGD system on a 750 MW Powder River Basin coal-fired unit.

The total additional capital requirement of a limestone with forced oxidation (LSFO) system over a lime spray drying (LSD) system is estimated to be $48/kW.

### 2.6.6 Operations and Maintenance Estimates

The operations and maintenance (O&M) costs of a FGD system include fixed O&M costs and variable operating costs. Fixed O&M costs account for operating, maintenance, administrative, and support labor, as well as maintenance materials. The additional fixed O&M costs of a LSFO system on a 750 MW PRB coal fired unit are estimated to be $1.76/kW-Yr more than that required for a LSD system.

The variable operating costs of an FGD system account for the cost of chemicals, solids disposal, and water. The variable operating costs of a wet LSFO system are estimated to be $0.17/MWh less than that of a LSD system. These costs include landfill disposal of flyash and absorber wastes at $5.30/ton in an on-site landfill.

The sale of combustion products has a dramatic impact on the variable operating costs of wet FGD systems. Even if no money is received for the sale of the flyash and gypsum, substantial savings result because of the avoidance of landfill costs. Appendix A provides a summary of wet FGD variable operating costs with credits for selling the flyash and gypsum.

### 2.6.7 Wet vs. Dry FGD Recommendations

A dry FGD system will have the lowest capital costs for the proposed facility. A dry FGD system will also likely have the lowest overall costs including capital and O&M. For most facilities firing PRB coal, a lime spray dryer is the preferred FGD technology. For facilities utilizing higher sulfur eastern

Bituminous coals or Illinois coals, a wet FGD system will be used. This decision is primarily driven by environmental requirements and not economic costs.

Other factors can influence the final FGD process selection. These will require a reevaluation of the process selection once the plant site is selected and permitting is underway. Permitting will be the most critical activity.

## 2.7 OTHER OPTIONS

Appendix A presents the incremental cost and performance changes for the other options outlined in the following sections.

### 2.7.1 Brownfield Site

Installation of a solid fuel generation resource at an existing coal plant site can result in significant capital cost savings due to sharing of existing infrastructure and operational savings due to shared staffing. The basis for the brownfield savings included in this analysis assumes the following:

- The existing site area is available for the expansion and will require minimal cut and fill, and rework of existing roads and facilities.
- Adequate administration, maintenance and warehouse facilities exist.
- The coal receiving, unloading and storage facilities exist and require only additional crushers and extension of conveyors to the new unit.
- The existing switchyard can be expanded for the new unit.

### 2.7.2 Coastal Location

Differential capital cost, operating cost, and performance cost estimates are provided if the Project is located on the coast and utilizes seawater for cooling. The basis for the cost estimates assumes the following:

- Additional piling under all foundations is required.
- Additional cut and fill to raise the site is required.
- Additional costs to accommodate the use of seawater for cooling tower and scrubber makeup.

### 2.7.3 Ship/Barge Unloading Facilities

The base case costs assumed rail delivery of fuel to an inland location. Differential capital costs are estimated for ship/barge unloading facilities in lieu of rail or in addition to rail. The estimate for such facilities assumes that the waterways exist with minimal need for dredging. However, new docking and unloading stations are included in the cost estimate. Costs include land based unloading systems.

### 2.7.4 Dry Cooling

If adequate cooling water resources cannot be secured, the Project can be constructed and operated with an air-cooled condenser (ACC) system, frequently referred to as dry cooling. An ACC system would result in increased capital costs and reduced performance.

### 2.7.5 Zero Liquid Discharge

If an adequate wastewater receiving body cannot be secured, the Project can be constructed and operated with a zero liquid discharge (ZLD) system. A side-stream softening/high-efficiency RO treatment system followed by a crystallizer is a common ZLD application. This system would result in increased capital and reduced performance. Further, a ZLD system would increase labor requirements (fixed O&M costs) and chemical requirements (variable O&M costs).

## 2.8 CAPITAL COST ESTIMATES

Two types of project capital costs were estimated for this study. All-inclusive project capital costs were developed that include direct construction costs, indirect costs, and all owners' costs. The only anticipated project costs not included in the all inclusive capital costs estimates are financing fees and interest during construction. Additionally, EPC capital costs were estimated for each alternative, which are essentially the all inclusive project costs minus the owner's costs.

The capital estimates provided in this assessment are based on the following capital cost assumptions. The capital costs are planning level only for use in comparative economic evaluations.

### 2.8.1 General Assumptions

- The plant site is a green field site that is clear of trees and wetlands and is reasonably level. There are no existing structures or underground utilities. The site will require filling around the equipment to raise the elevation above the groundwater level.
- Sufficient laydown area is available.

- Piling is included for major structures in all alternatives. Additional piling is included for the coastal locations for minor foundations.
- All administration, warehouse, storage and other single buildings are assumed to be single story pre-engineered metal buildings.
- An allowance has been included to install water wells for raw water supply for inland locations. For coastal locations, an allowance has been included to install an intake structure and outlet structure for cooling water supply to the salt-water cooling tower.
- The coal handling facility includes a rail loop and a rotary car dumper. Coal storage silos providing 3 days of live storage are included.
- The estimate includes the step up transformer(s) and switchyard costs. A 4-position ring bus switchyard is included for the alternatives with one generator. A 5-position ring bus switchyard is included for the alternatives with two generators. Two ¾ mile loop-in transmission lines are also included in the estimate.
- Construction costs are based on an EPC contracting philosophy for the facility. The EPC contract includes the boiler island, turbine island, and other associated equipment including the emission controls equipment.
- Escalation is included for a plant COD date of late 2010/early 2011.
- The construction labor rates are based on open-shop labor rates.

### 2.8.2 Indirect Cost Assumptions

The following EPC project indirects are included in the EPC capital cost estimates:

- Construction power and construction water interconnect
- Performance testing & CEMS/stack emissions testing
- Initial fills/consumables, preoperational testing, startup, startup management and calibration
- Construction/startup technical service
- Site surveys and studies
- Engineering/Construction Management
- Construction testing
- Operator training
- Startup spare parts

- Performance bonds
- Escalation
- EPC contingency
- EPC fee

These costs assume standard commercial terms and a well defined scope of work.

### 2.8.3 Owner Indirect Costs

The following Owner related indirect costs are included in the total project capital cost estimates:

- Project development costs
- Owner's operations personnel prior to COD
- Owner's engineer
- Owner's legal counsel
- Owner start-up engineering
- Permitting and licensing fees
- Land is included at $5,000/acre
- Startup/testing fuel, water, chemicals, start-up power, and a credit for test power sales.
- 30 days initial coal inventory
- Site security
- Operating spare parts
- Permanent plant equipment & furnishings
- Builder's risk insurance

## 2.9 OVERVIEW

All three of the conventional combustion technologies: Subcritical PC, Supercritical PC, and CFB, are viable and prudent technologies for Progress to evaluate in determining the best application for a new solid fuel generation resource in Florida. The primary advantage of the subcritical PC unit is lower overall capital costs and more operating history than the supercritical PC and CFB technologies. The primary advantage of the supercritical PC unit is improved performance and lower emissions compared to a subcritical unit. CFB technology would permit Progress to utilize a wider range of possible fuels including opportunity fuel such at petroleum coke. B&McD recommends all three technologies be further evaluated in combination with alternative fuel supplies.

IGCC technology is a newer technology to the power generation market and has experienced reliability issues in the past that make this technology less desirable. Many of the coal gasifier plants have experienced excessive down-time for design modifications and replacement of systems. There are IGCC technology suppliers that are claiming higher reliability, lower capital costs, and lower operating costs. However, such characteristics have not been demonstrated in utility plants constructed to date. Therefore, B&McD believes IGCC plant technology using coal gasifiers requires further development to be considered a reliable technology. B&McD does not recommend Progress further consider IGCC technology as a viable alternative.

# Section 3
# Fuel Supply Evaluation

# SECTION 3
# FUEL SUPPLY EVALUATION

## 3.1 OBJECTIVE

Hill and Associates (H&A) was retained to evaluate potential solid fuel sources suitable to supply the Project in Florida. Because the precise location of the proposed plant site is unknown, it was assumed that all coal will be delivered by rail or barge to the Tampa area in central Florida.

## 3.2 COAL PRODUCTION AND PRICE OVERVIEW

### 3.2.1 U.S. Coals

H&A projects that total U.S. coal production for 2003 will be 1.065 billion tons and this will increase to 1.094 billion tons in 2004 with most of the increase coming from PRB coal. The breakdown of production from each major U.S. coal producing region is shown in Table 3-1.

According to H&A's long-term forecasts of coal supply and demand, it is projected that U.S. coal production will steadily increase each year through 2009 to 1.309 billion tons and then fall to around 1.244 billion tons by 2022.

Coal prices for U.S. and international coal supplies are currently high due to some structural changes in the U.S. coal producing regions and abnormally high ocean freight rates, both of which have driven up international coal prices. H&A anticipates that too much U.S. coal production will be chasing the market in 2004, and this should result in lower steam coal prices.

A possibility exists that U.S. coal prices will continue their upward trend in the near term due to the following key issues: high eastern coal mining costs, especially in the Central Appalachian Region (CAPP); mining regulatory issues (such as valley-fill restrictions) and coal trucking issues in CAPP; high natural gas prices; very high European coal demand, which is increasing CAPP and Northern Appalachian coal exports; extremely high international shipping rates; lower Venezuelan coal production due to the national strike(s) in that country; and infrastructure constraints of the BNSF/UP joint rail line in the Power River Basin.

H&A forecasts coal prices for nearly 100 types of coal by modeling supply curves developed for each coal based on estimated cash costs for all existing mines and for reserves yet to be developed. Idle capacity and the potential for new project expansion for each coal region are also estimated, along with productivity changes in each region for a 20-year forecast period. Other related factors and prices, such as natural gas prices, $SO_2$ allowance prices, etc., are also considered by the model. All of these variables are input into an iterative model that considers three environmental cases and provides the marginal prices for each of the 100 different coals. Based upon the results of the most recent modeling, H&A forecasts the following price trends (in current dollars) for the U.S. coal regions in this study. The price ranges (in constant 2003$) shown are for the three environmental cases modeled:

- PRB coal prices will decline from around $6.50 per ton to around $3.00 - $5.80 per ton by 2022.
- CAPP (SWV near-compliance) coal prices will fall from $30.00 per ton to about $19.00 - $27.00 per ton by 2022.
- Western Pennsylvania (NAPP) coal prices will fall from around $30.00 per ton to about $15.00 - $28.00 per ton by 2022.
- Illinois Basin coal prices will fall from about $21.00 per ton to $14.00 - $18.00 per ton by 2022.
- Colorado-Green River mid BTU coal prices will decrease or increase (depending upon the environmental case considered) from $14.00 per ton to $10.00 - $16.00 per ton by 2022.

## Table 3-1

## U.S. PRODUCTION HISTORY & FORECAST 1998 – 2004

## Prepared by Hill & Associates

| COAL REGION | MSHA PRODUCTION 1998 MMT | 1999 MMT | 2000 MMT | 2001 MMT | 2002 MMT | Annualized First Half 2003 MMT | EIA ANNUALIZED SHIPMENT DATA TOTAL EIA 2002 MMT | Q1 2003 MMT | Q2 2003 MMT | Q3 2003 MMT | HILL QUARTERLY PRODUCTION FORECAST (Annualized) Actual Q1 2003 MMT | Actual Q2 2003 MMT | Proj. Q3 2003 MMT | Proj. Q4 2003 MMT | 2003 PROJ. PRO-DUCTION MMT | Proj. Q1 2004 MMT | Proj. Q2 2004 MMT | Proj. Q3 2004 MMT | Proj. Q4 2004 MMT | 2004 PROJ. PRO-DUCTION MMT | JANUARY 2004 EST. PROD. CAPACITY MMT |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NORTHERN APPALACHIA | 158 | 141 | 138 | 144 | 127 | 126 | 132 | 125 | 137 | 129 | 127 | 125 | 126 | 135 | 128 | 138 | 133 | 138 | 144 | 138 | 140 |
| CENTRAL APPALACHIA | 278 | 263 | 261 | 267 | 248 | 227 | 245 | 238 | 272 | 194 | 231 | 222 | 223 | 223 | 225 | 219 | 219 | 223 | 223 | 221 | 221 |
| SOUTHERN APPALACHIA | 23 | 20 | 19 | 19 | 19 | 21 | 18 | 17 | 25 | 17 | 20 | 22 | 18 | 19 | 20 | 20 | 20 | 18 | 18 | 19 | 20 |
| ILLINOIS BASIN | 111 | 104 | 93 | 95 | 92 | 91 | 96 | 83 | 96 | 98 | 91 | 91 | 89 | 96 | 92 | 95 | 95 | 93 | 100 | 96 | 101 |
| POWDER RIVER BASIN | 340 | 359 | 362 | 391 | 397 | 387 | 399 | 374 | 323 | 484 | 380 | 393 | 405 | 421 | 400 | 412 | 426 | 436 | 436 | 428 | 443 |
| COLORADO | 30 | 30 | 29 | 33 | 35 | 34 | 32 | 32 | 34 | 35 | 33 | 34 | 39 | 38 | 36 | 38 | 33 | 36 | 36 | 36 | 38 |
| UTAH | 27 | 25 | 27 | 27 | 25 | 27 | 27 | 25 | 28 | 25 | 28 | 25 | 23 | 25 | 25 | 25 | 23 | 23 | 23 | 24 | 27 |
| | 967 | 942 | 930 | 978 | 949 | 911 | 949 | 893 | 915 | 981 | 910 | 912 | 923 | 957 | 926 | 947 | 949 | 967 | 980 | 961 | 990 |
| OTHER U.S. | 154 | 154 | 150 | 148 | 149 | 143 | 140 | 152 | 158 | 158 | 150 | 148 | 152 | 152 | 151 | 151 | 148 | 148 | 150 | 149 | 150 |
| TOTAL US PRODUCTION | 1121 | 1097 | 1080 | 1126 | 1098 | 1054 | 1090 | 1044 | 1074 | 1139 | 1060 | 1060 | 1075 | 1109 | 1076 | 1098 | 1097 | 1115 | 1130 | 1110 | 1140 |
| U.S EXPORTS | 78 | 59 | 59 | 45 | 42 | 33 | 42 | 30 | 36 | 38 | 30 | 36 | 38 | 38 | 36 | 36 | 36 | 38 | 38 | 37 | 38 |
| TOTAL DOMESTIC SHIPMENTS (EXCLUDES EXPORTS) | 1043 | 1038 | 1021 | 1081 | 1056 | 1021 | 1048 | 1015 | 1038 | 1101 | 1030 | 1024 | 1037 | 1071 | 1041 | 1062 | 1061 | 1077 | 1092 | 1073 | 1102 |
| U.S. IMPORTS | 9 | 9 | 13 | 20 | 17 | 23 | 17 | 22 | 23 | 23 | 20 | 26 | 25 | 25 | 24 | 23 | 20 | 20 | 20 | 21 | 25 |
| **NET DOMESTIC SHIPMENTS** | 1052 | 1047 | 1034 | 1101 | 1073 | 1044 | 1064 | 1037 | 1061 | 1124 | 1050 | 1050 | 1062 | 1096 | 1065 | 1085 | 1081 | 1097 | 1112 | 1094 | 1127 |

### 3.2.2 International Coal

World-wide hard coal production amounts to about 3.837 billion tons per year from China, Asia, Latin America, Africa, former USSR, and other OECD countries. Slower growth in Asian coal demand is expected in the future and European coal demand also may be lower due to Kyoto objectives and expected substitutions of coal with biomass, renewables and natural gas supply in European countries.

International steam coal demand for electricity generation is about 431.6 million tonnes per year and estimates suggest that it will increase by about 16.3% to around 502.0 million tonnes by 2011.

International coal prices are currently well above normal levels. This is attributable to a number of factors: high U.S. coal prices (especially CAPP coals); high oil prices, which have risen from around $16.00 per barrel in December 2001 to over $31.00 at the present time; high natural gas prices; abnormally high ocean freight rates; and a recent reduction in U.S. coal synfuel production due to an IRS review of synfuel production processes.

Various qualities of coal from the major coal producing countries, such as Colombia, Indonesia, Australia, South Africa, and Venezuela have been modeled. According to base case projections, it is forecasted that the following FOBT market prices for Colombian coals from around $25.50 per tonne in 2002 (the base year) to around $28.54 per tonne in 2011. This is for 11,700 BTU, 0.6% sulfur coal from the Drummond mine.

## 3.3 FUEL TYPE ALTERNATIVES

The following fuel alternatives are reviewed in more detail:

- Powder River Basin Coal (PRB)
- Central Appalachian Coal (CAPP)
- Northern Appalachian Coal (NAPP or PITT)
- Illinois Basin Coal (ILB)
- Colombian Coals (IMPORT)
- Petroleum Coke (PETCOKE)

### 3.3.1 Powder River Basin Coals

The PRB is comprised of sub-bituminous coal production principally from mines in northern Wyoming and southern Montana. The coal is low in BTU value, ranging from 8,000 – 9,000 BTU, and is very low in sulfur content, ranging from 0.3% to 0.8%. The PRB is the largest coal producing region in the U.S., accounting for almost 400 million tons of annual coal production. This is almost half of all U.S. coal production, as shown in Table 3-1.

The coal is shipped to markets within the U.S. by rail, or rail-to-water, with some local deliveries by truck. Two major railroads, the BNSF and UP, originate almost all of the PRB shipments, and then deliver the coal directly to power plants or to rail-to-barge docks for water delivery to other plants. The PRB mines are very large and almost all of the coal is surface mined. The mines have very low overburden ratios, which explain why coal mining productivity is high and costs in the PRB are very low. Typical ratios in the Basin are around 2.8:1. Mining in the PRB is controlled by a small number of producers with most of the mine ownership in the hands of less than six major suppliers.

In 2003, three companies, Peabody, Arch, and Kennecott, controlled 72% of the total PRB coal production. Vulcan and RAG each controlled about 10.5%, and Westmoreland controlled 3.9% of the coal production. In 2003, Kennecott was projected to be the largest producer with 28.6% of the total PRB coal production, followed closely by Peabody with 27.3%, and Arch with 16.0%.

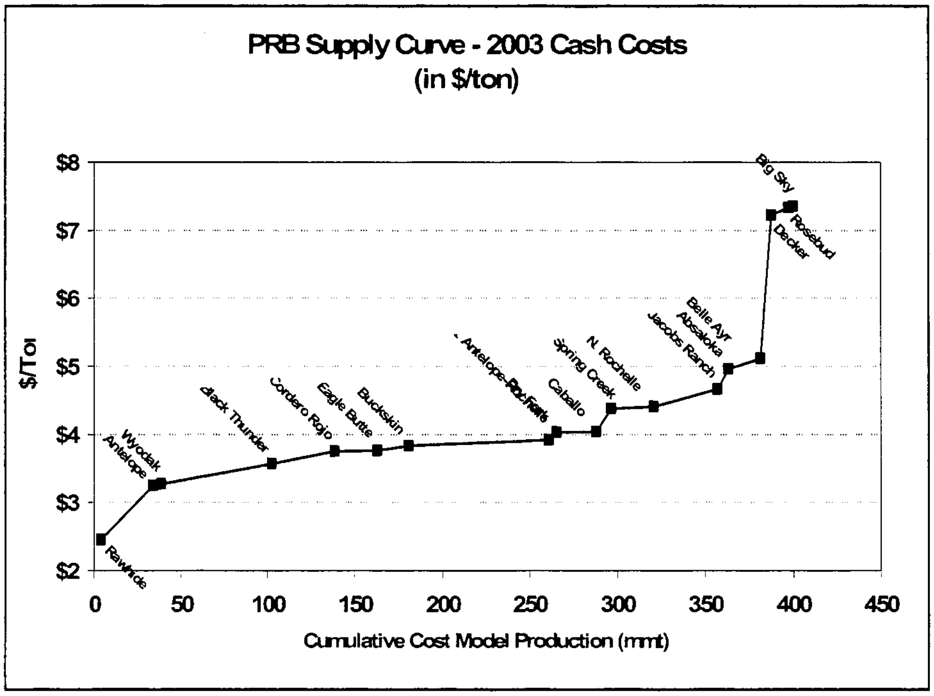
There is further concentration occurring in the Basin as Triton Coal is currently in the process of selling its coal properties, possibly to Arch, which already owns significant production there. Arch has a $364 million offer to buy Vulcan/Triton's Buckskin and North Rochelle mines, which will allow Arch to combine the Black Thunder and North Rochelle mines into one mega-complex. Currently under anti-trust scrutiny, the sale is expected to be finalized sometime in early 2004. If Arch acquires Vulcan/Triton, it will control almost 27% of the PRB production, and this will place it in a comparable competitive position with Peabody and Kennecott. RAG recently announced that it's U.S. mining operations are up for sale. At this time, it looks like RAG's PRB mines (Belle Ayr and Eagle Butte) will probably change hands in 2004. The government could possibly stop the sale of these properties to either Arch or Peabody because of market power or anti-trust issues.

After increasing for years, PRB mine productivity remained flat from 1998 through 2001. Then, for the first time in over 20 years, PRB productivity dropped, resulting in higher mining costs in 2002.

Technological improvements are being offset by increased mining ratios, more unstable overburden, increased coal haulage costs and the hiring of new, inexperienced miners.

With 2003 production levels at comparable levels to 2002, productivity did not increase and overall costs did not improve. Thus, 2002 and 2003 costs were $0.25-0.50/ton higher than costs in 2001. Producers are projecting 428 million tons of production in 2004, and if this level of production is reached, productivity should return to 1998-2001 levels and costs should drop. Over time, however, increasing ratios and haul distances, and high reserve acquisition prices will continue to place upward pressure on costs. Continuing productivity improvements will somewhat offset these higher costs. Figure 3-1 shows the supply curve for 2003 cash costs in the PRB.

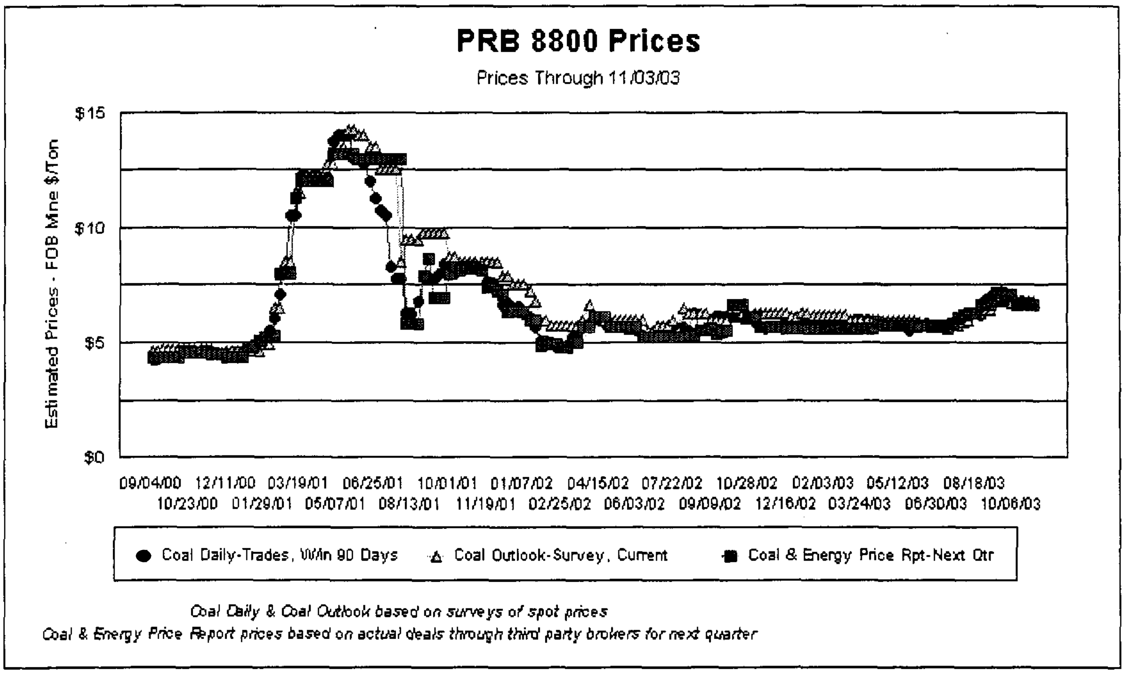
**Figure 3-1**




The PRB has tremendous expansion potential, if demand warrants. Existing mines can easily expand and numerous new projects can be developed as demand increases. The PRB could easily expand production levels to more than 600 mmtpy. The biggest constraints are demand (which will probably not exceed 500-600 mmtpy); the amount of capital needed to make the expansion, the quality of coal that could be produced out of competing regions, and the transportation infrastructure.

Prices for PRB coals are up in 2003 due to strong demand, high prices for CAPP coals, and higher mining costs. H&A believes that prices will continue to be bullish over the next few years because producers and the railroads are expected to exhibit more restraint in expanding capacity. The continuing cutbacks in Central Appalachia will also contribute to price volatility. Figure 3-2 shows the market price history for PRB 8800 BTU coals from September 2000 through early November 2003.

**Figure 3-2**




Key Issues and Market Drivers for the PRB:

- Large mines are controlled by a few major coal producers (Peabody, Arch, RAG, Kennecott, etc).
- Potential further consolidation of mine ownership is possible.
- The Basin contains substantial coal reserves.
- Latent production capacity can be quickly expanded to meet demand.
- Mine production costs are low, but are increasing over time.
- Productivity has declined in recent years from previously higher levels, but it may increase again in the next few years.
- The mines are principally served by either BNSF or UP railroads. Few mines are served by both railroads, but there is some sharing of rail traffic on the BN/UP joint line.

- Rail rates from the mines to various destinations including barge transfer facilities are generally much lower ($ mils per ton-mile) due to longer rail hauls.
- There are a number of western railroad issues (congestion, expansion limitations, etc.). Among them:
    - In late 2003, the BNSF/UP Joint Line railroad has not been able to keep up with demand. It appears that limited funds have been spent on maintenance to keep trains moving efficiently. By the second half of 2004, triple tracking at Shawnee-Walker Junction may be required to keep up with shipments.
    - The BNSF/UP Joint Line railroad shipping capacity in the Wyoming PRB will probably be exceeded by mid-year 2004, which will require infusion of new capital by the BNSF and UP into the line's infrastructure. This could restrict some coal shipments of PRB coals until the infrastructure is built.

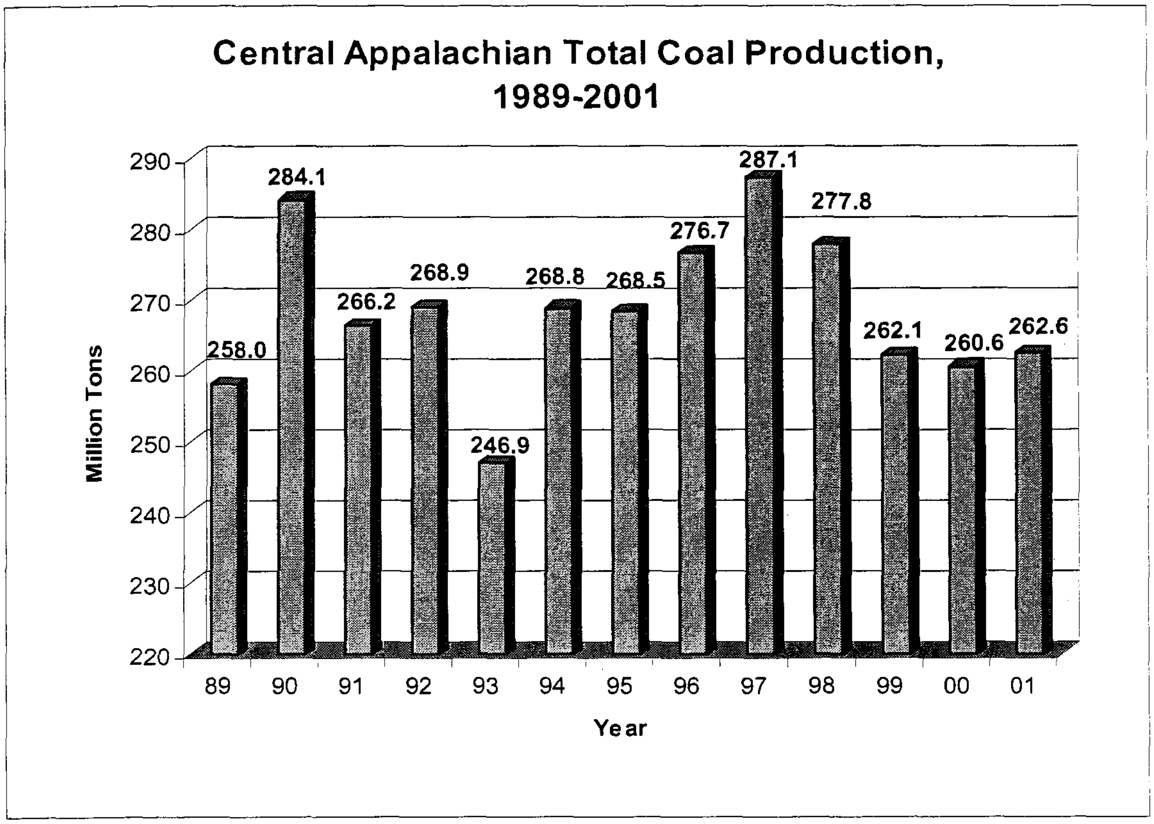
### 3.3.2 Central Appalachian Coals

The CAPP coal region is comprised of bituminous coal production principally from mines in southern West Virginia, eastern Kentucky, and southwest Virginia. The coal is generally high in BTU value, ranging from 12,000 – 13,000 BTU, and is low in sulfur content, ranging from 0.7% compliance coals up to 2.0% sulfur coals. The CAPP is the second largest coal producing region in the U.S., accounting for about 225 million tons of annual coal production. This is almost one-fourth of all U.S. coal production. The coal is shipped to markets within the U.S. by rail, or rail-to-water, with some local deliveries by truck. Two major railroads, the NS and CSX, originate a great deal of the CAPP shipments, and then deliver the coal directly to power plants or to rail-to-barge docks for water delivery to other plants. Some CAPP coals are also exported through a number of eastern U.S. ports.

There have been numerous changes to the mining trends and outlook for the Central Appalachian coal industry over the past few years. A recent ruling by a federal judge has threatened the future of surface mining in the region. Environmental groups and the general public have gained momentum in their challenges to the coal industry, on issues such as: refuse impoundment stability; coal truck weight limits (especially in West Virginia); cumulative hydrological impact assessments; and longwall subsidence.

The bulk of the remaining reserve base in Central Appalachia is characterized by thinner seams and associated geological problems. Most of the high quality thick coal has been mined. There are few large blocks of coal remaining that can be extracted using longwalls or draglines. Over time, mines in this region will have trouble maintaining the productivity growth of the past few decades. Productivity levels and production will decline in the future, and productivity growth is likely to slow significantly. Figure 3-3 shows the annual CAPP production variations from 1989 through 2001. It is now projected that CAPP production will end up around 225 million tons for 2003 and fall further to 221 million tons for 2004.

**Figure 3-3**




Industry consolidation in the CAPP region has been robust. In 1998, the constellation of large producers changed dramatically as Massey added to its portfolio of properties; AEI Resources added substantial holdings in the late 1990s; Arch and Ashland merged into Arch Coal; AEI Resources purchased Zeigler Coal and Cyprus Amax's eastern operations; and James River bought Blue Diamond, much of Transco and Sun. As a result of these and other transactions, the eleven companies that produced over five million tons grew.

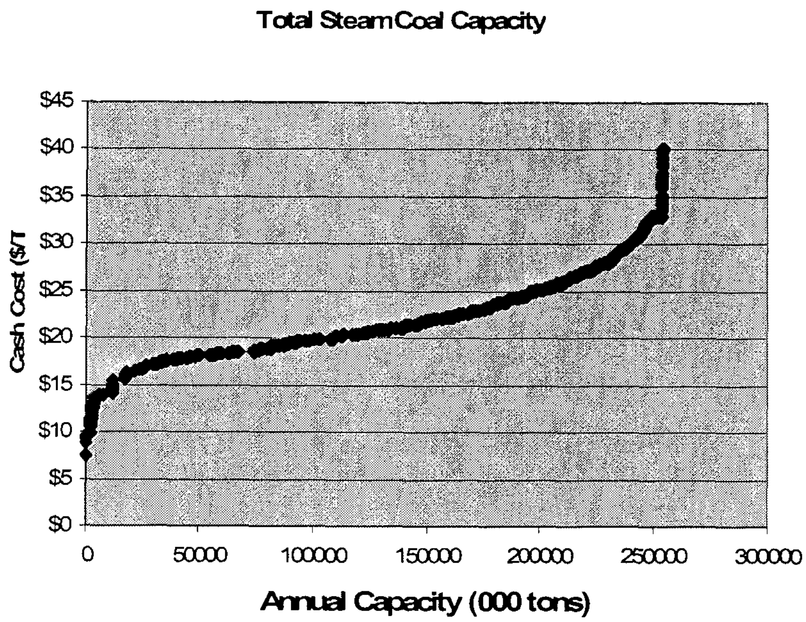
Massey has increased production and now holds a firm lead on Central Appalachian production at nearly 48 million tons. Arch's production was about five million tons less than it was in 1998, about equal to the production lost at Dal-Tex. Production at AEI fell by about ten million tons due to the sale of Crockett

Collieries, depletion of surface reserves at Cannelton, depletion of reserves at Armstrong in Fayette County and the splitting off of some surface reserves to Larry Addington under the name of Appalachian Fuels. RAG's production increased largely through the acquisition of the Camp Creek and Laurel Creek properties from International Industries. Quaker shut down some high-cost operations in eastern Kentucky prior to filing for bankruptcy and being purchased by AEP. The total production for the AEP Kentucky property is now about four million tons less than what Quaker was producing in 1998. However, AEP is now in the process of selling these properties. In summary, concentration in the region has been significant. This has allowed some of the companies, such as Massey, to command higher prices in the market due to their control of so much CAPP coal.

When prices went very high in 2001, CAPP producers (as well as the rest of the country) opened higher cost mines to meet the demand. H&A now projects that CAPP production will end up at 224 million tons in 2003 and 221 million tons in 2004.

Cash costs for production in CAPP have been steadily increasing due to regulations, decreasing productivity, thinner coal seams, reserve depletion, and deeper coal reserves. Figure 3-4 shows the steam coal mine cash costs for the cumulative potential production capacity in Central Appalachia. The figure shows FOB cash costs ranging from just over $10 per ton to upwards of $35.

Figure 3-4

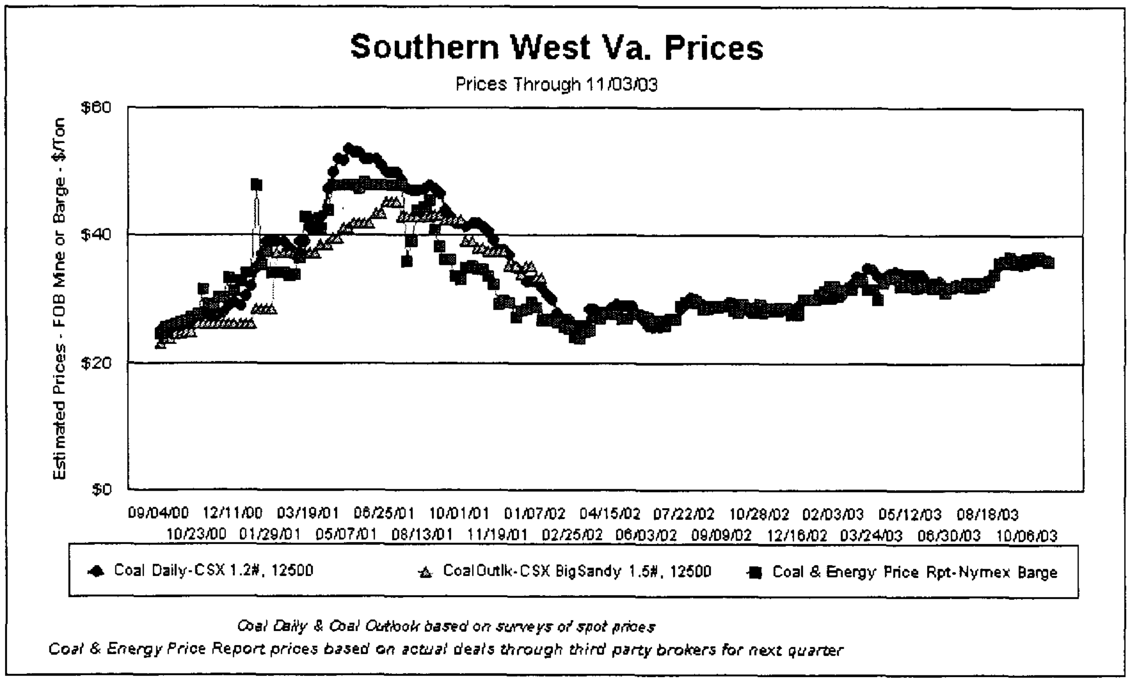



The supply curve suggests that the marginal cost of production will be about $25 per ton at the 200 million tpy production level. Coal prices in the high $20s per ton range will be required for all producers with cash costs above $25 per ton to remain viable. Some of the higher cost production is supported with high-priced contracts or industrial sales, and some of the higher costs are at mines that have closed.

The financial status of coal companies that operate in the region has been negatively impacted despite the high prices in 2001. A number of large companies, including Pen Coal, AEI Resources, Lodestar, Quaker Coal, and James River filed for Chapter 11 bankruptcy protection. Many financial institutions have become reluctant to back new projects. As a result, it is projected that production in the region will continue to decline.

Coal prices rose in 2001, but few companies had the ability to offer additional tonnage into the spot market to take advantage of the situation. A number of smaller mines opened, but the prices failed to hold and, with the mild winter of 2001-2002, the market rapidly became oversupplied. Many companies cut back production and trimmed work schedules in hopes of bringing the market back into balance. Figure 3-5 shows the market prices of CAPP (Southern WV) coals from September 2000 to early November 2003.

**Figure 3-5**




Key Issues and Market Drivers for CAPP:

- Rapid depletion of coal reserves is occurring (substantial decreases have occurred in the past three years and more are to come).
- Coal production costs are high, primarily due to deteriorating geologic conditions.
- Large mines are controlled by a few major coal producers (Peabody, Arch, Massey, etc.), but there are many smaller mines in the region.
- Most mines have either CXS or NS rail service, but not both.
- Some mines have access to waterways, but at additional trucking or rail cost to the docks.
- Productivity is declining due to harder-to-reach coal.
- There are significant trucking issues in West Virginia, resulting in higher trucking rates.
- There are significant coal mining regulatory and environmental issues in West Virginia (hollow-fills and Section 404 permits).

### 3.3.3 Northern Appalachian Coals

The Northern Appalachian coal region is comprised of bituminous coal production principally from mines in northern West Virginia and western Pennsylvania. The coal is generally high in BTU value, ranging from 12,000 – 13,300 BTU, and is mid-to-high in sulfur content, ranging from about 2.2 % - 5.0 %. The NAPP is the third largest coal producing region in the U.S., accounting for about 128 million tons of annual coal production.

The coal is shipped to markets within the U.S. by rail, or rail-to-water, with some local deliveries by truck. As with CAPP, two major railroads, the NS and CSX, originate a great deal of the NAPP shipments, and then deliver the coal directly to power plants or to rail-to-barge docks for water delivery to other plants.

Production from this region has taken place for over 200 years and will continue for years to come. The Pittsburgh seam (PITT) ranges from 5 to 8 feet thick and it is laterally extensive. As such, the seam is conducive to large scale, longwall mining methods. Almost 97% of Pittsburgh seam production comes from longwall operations, which provides for highly mechanized, very high productivity and very low cost coal mining. This has enabled the market prices for Pittsburgh seam coals to remain very low over the years and maintain a highly competitive presence in both U.S. and export coal markets.

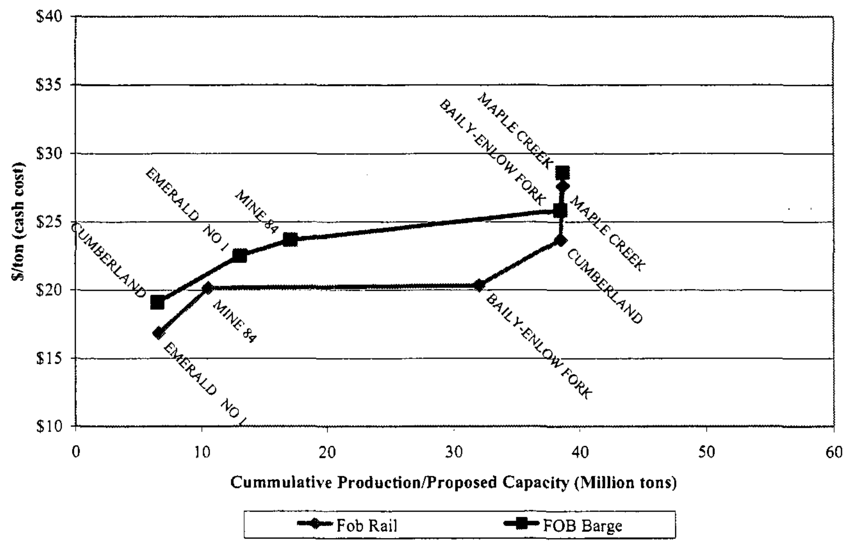
Production from NAPP for 2003 is estimated to reach 128 million tons. By 2004, another 10 million tons could be developed and production could increase to 138 million tons, mostly driven by brownfield expansions. Assuming the market conditions exist, several new greenfield mines could open up in the 2005-2011 timeframe. If so, Pittsburgh seam production could expand to 150 mmtpy by 2011. All proposed greenfield operations will be in mid to high sulfur coal.

The $SO_2$ credit bank will be depleted around 2005, thus with a depleted credit bank and tighter $SO_2$ limits under the National Ambient Air Quality Standards (NAAQS), power plants will likely add scrubbers. Because of the strong reserve base and relatively low costs (as compared to other producing regions), Pittsburgh seam mid and high sulfur coal will likely be the benefactors of this new demand.

The NAPP supply curve shows the low-cash mining costs for the region, ranging from around $16.00 to $28.00 per ton, as shown in Figure 3-6.

**Figure 3-6**

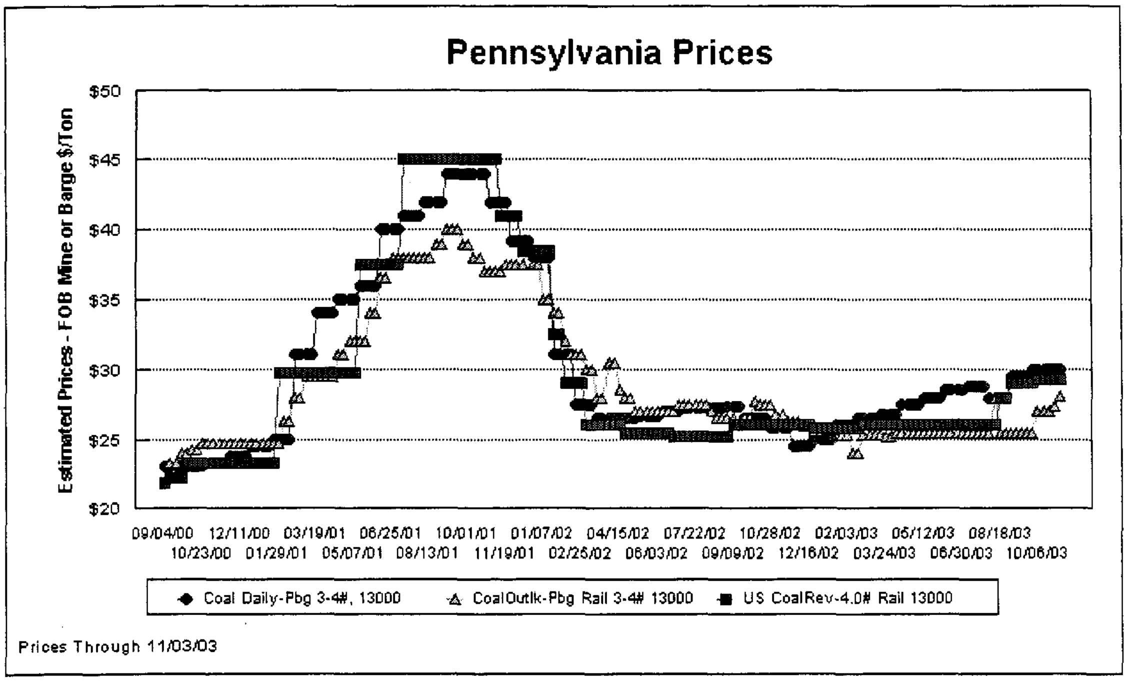
**Coal Supply Curve for Pennsylvania Mines**
**2003**




According to long-range forecasts, it is projected that mining costs in this region may decrease somewhat to a range of $14.00 to $26.00 per ton by 2011, based upon improvements in productivity and the replacement of old longwall mining equipment with newer and more efficient ones. There is a possibility that productivity improvement projections may not materialize because the coal seams are getting thinner and underground coal haulage will be longer. However, it is anticipated that overall productivity in the region will increase over the next 8 – 10 years.

Market prices for Pennsylvania coals have varied widely from a low of around $21.00 per ton in late 2000 to $45.00 per ton in late 2001. Prices are currently at much lower levels than in 2001, but they have risen steadily throughout 2003, as shown in Figure 3-7.

**Figure 3-7**




If producers show constraint in the market as they have done recently, prices may again spike in the 2004-2008 timeframe to meet the increases in demand. With demand increasing by 20 to 25 mmtpy during this period, producers will seek a guaranteed ROI to open new mines to meet this new demand. Therefore, prices could spike to above their present levels of around $30.00/ton.

Key Issues and Market Drivers for NAPP:

- There are significant coal reserves and potential for expansion.
- Mining productivity is high and production costs are low at many mines due to long-wall mining.
- Most of the large mines are controlled by a few major coal producers (Consol, RAG, etc.).
- There are many smaller mines, but they principally serve local industrial and utility plants.
- There is significant production capacity that has access to both CXS and NS rail service (e.g. CONSOL's Bailey and Enlow Fork complexes).
- A limited number of mines have access to waterways at additional cost of transportation to get to the docks.

### 3.3.4 Illinois Basin Coals

The Illinois Basin (ILB) coal region is comprised of bituminous coal production principally from mines in western Kentucky, Indiana, and Illinois. The coal is wide ranging in quality, generally ranging from 10,000 – 12,800 BTU, and from about 0.5 % - 5.0 % sulfur. The ILB is the fourth largest coal producing region in the U.S., accounting for about 92 million tons of annual coal production.

The coal is shipped to markets within the U.S. by rail, or rail-to-water, with some local deliveries by truck. As with some of the other regions, two major railroads, the NS and CSX, originate a great deal of the ILB shipments, but there are many regional (short-line) railroads that deliver these coals. These Class I and regional railroads deliver the coal directly to power plants or to rail-to-barge docks for water delivery to other plants. The Illinois Basin is able to get a number of its coals to the waterways, much more so than some of the other regions. Because of their close proximity to the nations' river system, West Kentucky producers have the lowest production costs in the barge. Indiana and Illinois have the lowest cost in the rail car.

The Basin contains a tremendous underground reserve base, which is 5-10 times larger than the Pittsburgh 8 seam reserve base in Northern Appalachia. As the surface reserves deplete and as demand increases, these reserves will likely be developed in the next ten years.

The high prices and strong demand during 2001 allowed Illinois Basin production to rebound from 93 million tons (mmt) in 2000 to 95 mmt in 2001; however, the high prices of 2001 also allowed other regions to expand in coal production. A mild 2001/02 winter, a new generation of gas plants, and a poor economy, drove coal demand down and stockpiles up, which resulted in a drop in Illinois Basin production to 92 mmt in 2002. Prices dropped accordingly. The Basin's production is expected to remain flat at 92 mmt in 2003 and is forecasted to increase to 96 mmt for 2004. With continuing mine expansions taking place in 2003, and 2004, this should continue an existing oversupply condition for this coal through 2004.

H&A's ten-year analysis has identified enough projects to suggest that Illinois Basin capacity could potentially increase to more than 200 mmtpy by 2013, if such demand is present; however, production will probably only be in the 108-110 mmtpy range.

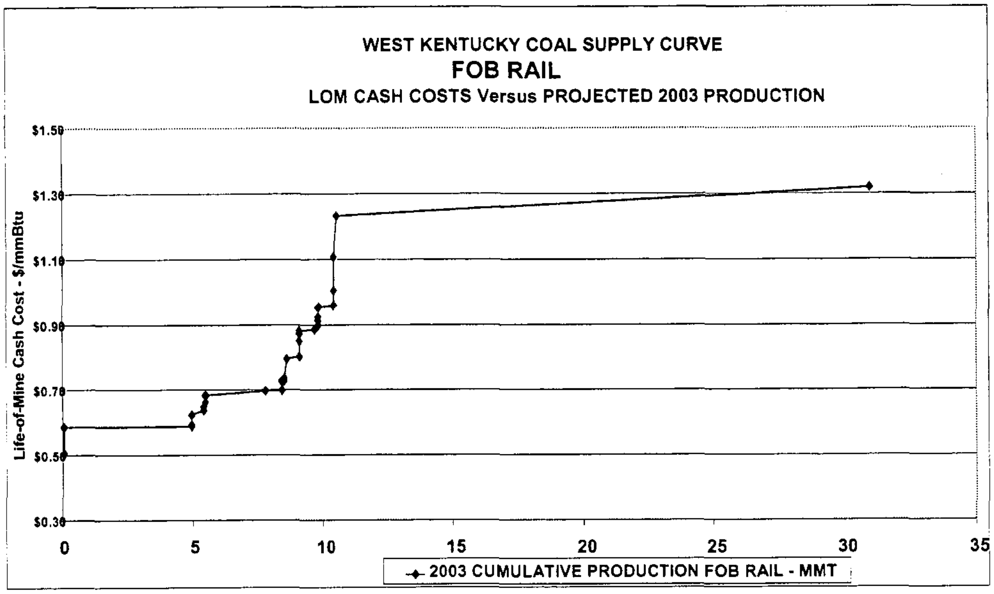
Peabody is the dominant producer in the region. It now controls 36% of the Basin's production and is in position to maintain or expand this dominance through 2013. Alliance and Robert Murray are distant seconds. The other two producers in the top five are Horizon and General Dynamics' Freeman United. Horizon is in financial trouble and is struggling to stay alive. It has already shut down one operation in 2003 and will likely shut down a couple more in the next few years, so it will probably drop out of the top five by 2005. Freeman United has survived and is struggling to maintain production levels. It, too, could drop out of the top five in 2-3 years.

Consolidation in the Basin during the 1990s was great. During 2001 and 2002, it had slowed, but in 2003 it has picked up again. In 1997, the top 15 producers in the Basin controlled 82% of the production. In 2001 and 2002, the top 15 controlled 94% of the production; however, in 2003, the top 15 control nearly 98% of the production. The top five producers control 72% of the Basin's production in 2003 (as compared to 49.4% in 1997).

Overall mine productivity has dropped by 10-15% over the last two years, mainly due to under utilized mines, and the higher prices of 2001, which allowed new mine development in higher cost reserves. Mine costs are up 10% as a result of this, which will hurt Illinois Basin demand in the future, as it has to compete with lower cost alternatives.

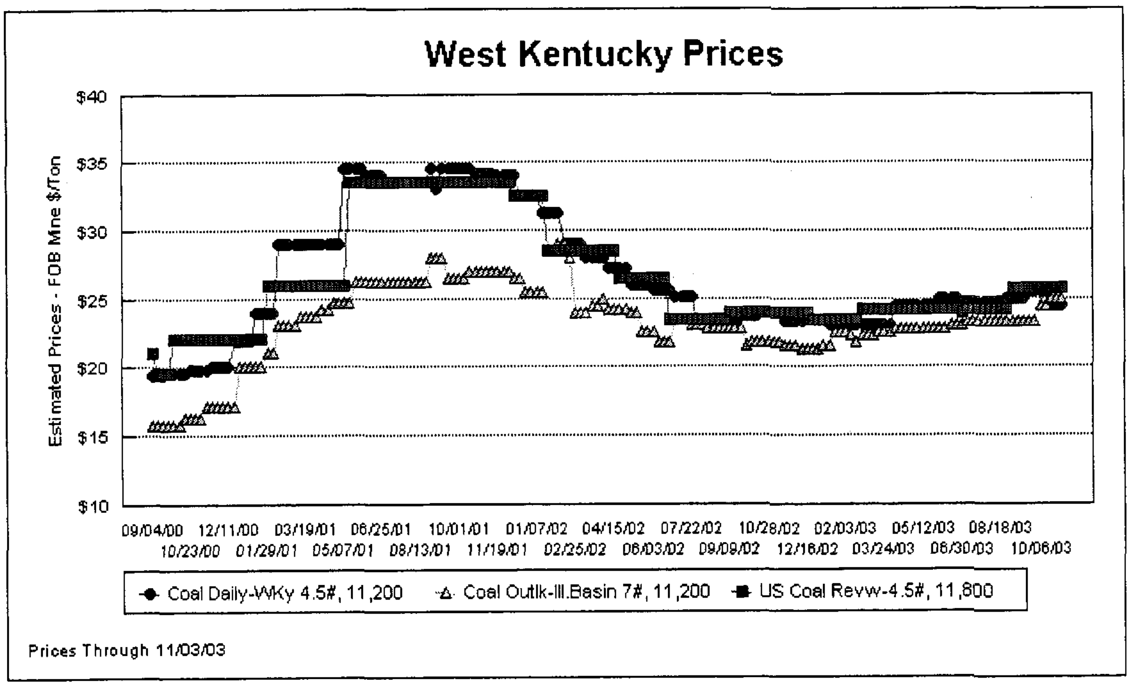
H&A's forecast of ILB coal prices factors in the value of $SO_2$ emission allowances and, in the out years, assumes that all producing regions, including the Illinois Basin, are in an oversupply situation. Thus, prices are determined by the marginal cash costs on the supply curve, as shown in Figure 3-8. This figure shows that the cash costs for West Kentucky production ranges from around $0.60/mmbtu ($14.00 per ton) to about $1.30/mmbtu ($30.00 per ton).

**Figure 3-8**




Prices for Illinois Basin coals have also been variable, depending upon prices from other coal supply regions, gas prices, etc., ranging from a low of $15.00 per ton in late 2000 to as high as $35.00 per in 2001. Current prices are around $25.00 per ton, as shown in Figure 3-9.

**Figure 3-9**



Key Issues and Market Drivers for ILB:

- Tremendous coal reserves exist and significant expansion is possible in the ILB.
- The large mines are controlled by a few major producers (Peabody, Alliance, Freeman, Consol, etc.), but there are also a number of smaller mines in the region.
- Most mines have either CXS or NS rail service, but not both.
- Some mines have access to waterways, but at additional transportation cost to the docks.
- Production has declined in recent years.
- The region will benefit if scrubbers are installed to meet air quality requirements.

### 3.3.5 Colombian Coals

The Colombian coal industry (IMPORT) is comprised of bituminous coal production principally from the following coalfields: Cerrejón, La Loma, and La Jagua. The coal is mid-to-high BTU, ranging from 11,400 – 12,200 BTU, and is very low in sulfur content, ranging from 0.6% to 0.8%. Colombia produces and exports about 42 – 45 million tonnes of coal annually to various markets in the U.S. and to other countries. It is projected that Colombian production and exports will grow to as much as 52 - 54 million tonnes by 2006.

The country is a primary exporter of coal, and it has enormous amounts of coal equivalent to almost 9 billion tonnes of measured reserves. About 90%, or 6.65 billion tonnes, of the country's coal reserves are for steam coal use.

The vast majority of export tonnage comes from the Cerrejon, La Loma, and La Jagua regions. These three regions contain the bulk of the defined coal resources and offer relatively easy access to the coast. The mines in these regions share similar characteristics:

- Almost all production comes from surface operations.
- All are mining multiple seams at stripping ratios of approximately 6.5:1.
- In most, the seams are steeply pitched and lend themselves to truck and shovel methods.
- All have high quality coal with low sulfur and ash and medium to high BTU values.
- Each region now has one large mine and one or more smaller operations.

Most of the mines in Colombia move their coal by truck to huge ports on the coast. A few mines have access to rail. A few other producers use barges on the Magdalena River to get the coal into vessels. The expansion of rail service to additional mines will probably come in due time, but this project has been slow to develop.

Two major railroads, the Cerrejon Railroad and Atlantic Railroad, transport most of the rail-origin coals in Colombia. These rail shipments are delivered to a number of huge ports for vessel-borne water delivery to plants in the U.S. and the other countries. The coal is shipped to markets within the U.S. by ocean-going vessels of various sizes.

Most of the mining in Colombia was structured with high-level government participation, but the government divested its ownership and changed its role to controlling and promoting Colombian coal production. Most of the production is controlled by a small number of producers with the mine ownership in the hands of about 3 major supplies: Cerrejon Coal Company (BHP, Anglo American and Glencore); La Loma (Drummond); and Paso Diablo. A number of smaller mines are owned by a mix of domestic and foreign companies.

The Colombian coal industry increased coal production during 2001, mainly by production increases at Drummond and Cerrejón Coal mines. Drummond showed the largest growth in 2001, increasing production by 3.3 million tonnes. On the other hand, the Cerrejón Coal increased production by 1.4 million tonnes.

During 2002, the production increase from 2001 was partially offset by a production reduction of about five million tonnes, decided by the major Colombian coal supplier, the Cerrejón Coal Company, which was the resulting company after the consolidation of Carbones del Cerrejón and Cerrejón North Zone.

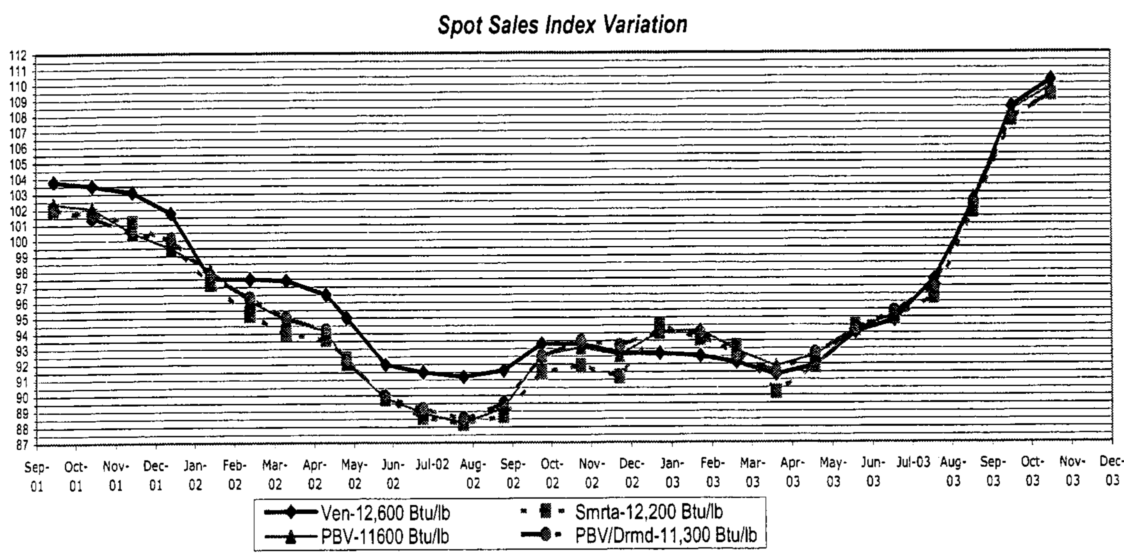
Currently, Colombia and Venezuela have the infrastructure in place to ship nearly 48 million tonnes of coal per year. Because these figures do not assume the construction of a railroad in Venezuela, the potential for low-cost tonnage is even greater than stated above. However, the project of developing a deep-water direct vessel loading facility and an efficient coal transportation system in Venezuela does not appear to have government support. This fact leads coal market players to believe that a transport system will not be developed in the near future. Venezuelan production is down by 10% in 2003 due to the general strike that occurred earlier this year, and most producers have commitments for their production through 2004.

Consolidation of mines in Colombia will bring more discipline to the supply side of the coal market. New Cerrejón owners have a different market strategy. Cerrejón Coal Company is now a "swing producer" and its output level will depend on the coal prices in South Africa and North America. If South African coal prices lower due to an excess of coal supply in the international market, Cerrejón Coal Company will continue withholding production increases. If necessary, Cerrejón Coal will reduce production as it was forced to do in 2002. Cerrejón's production forecast for 2003 is currently 22 million tonnes.

Current prices for Colombian coals are high. Figure 3-10 shows the significant increase in Colombian and Venezuelan coal prices from September 2001 through November 2003. These higher prices are attributable to high U.S. coal prices, higher ocean freight costs and overall increases in world-wide coal demand.

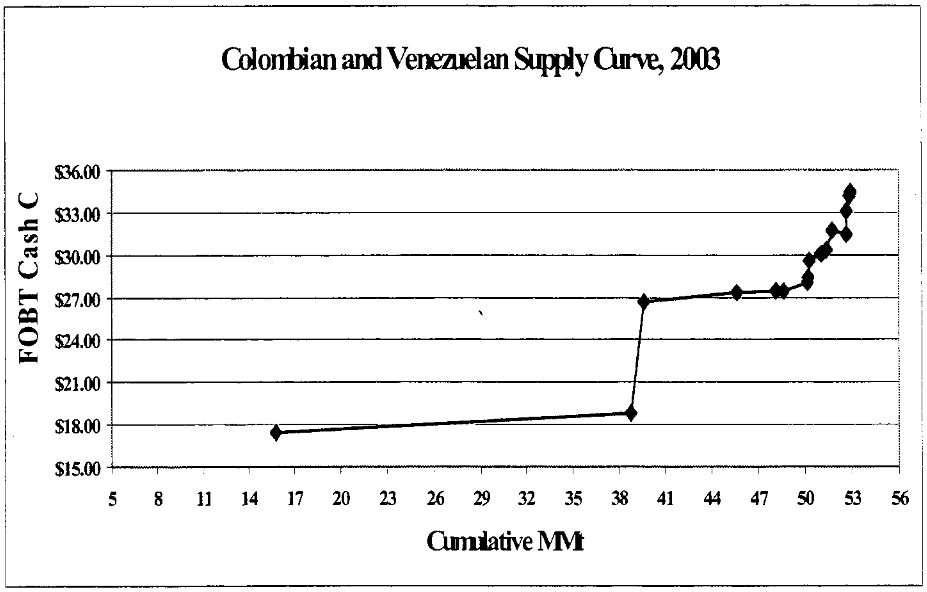
**Figure 3-10**

**Colombian & Venezuelan Prices**




As shown in Figure 3-11, the Latin American coal supply curve shows about 32 million tonnes per year of export capacity available at an FOBT cash cost of less than US$18 per tonne. In addition, there will be another 16 million tonnes available at progressively higher costs.

**Figure 3-11**




Key Issues and Market Drivers for Imported Coals:

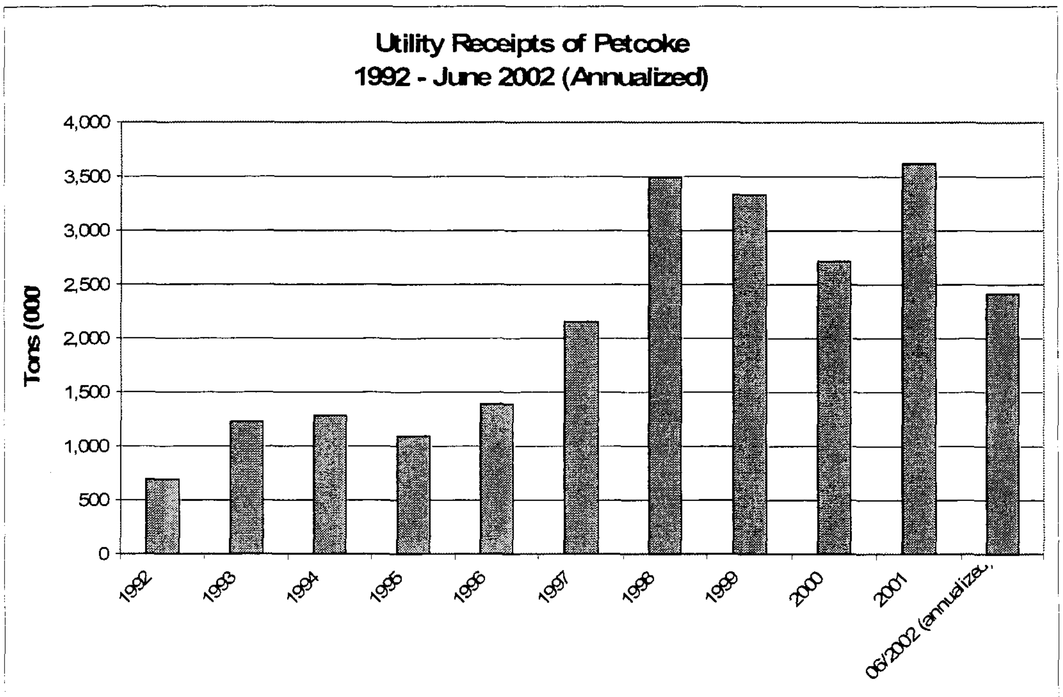
- Enormous amounts of coal exist in Colombia.
- Coal production is controlled by a small number of major coal producers.
- Coal production costs are low.
- Large coal loading ports have been built for exports.
- Imports are making in-roads into the U.S.
- Prices are generally competitive with U.S. coal supplies, but they are subject to global competition for the coals.
- A high degree of political and civil instability exists in Colombia.
- Very high ocean freight rates exist at the present time – likely to ease but not soon.
- U.S. railroads have been reluctant to provide cost-competitive rail rates for imported coals destined for inland plants in the U.S.

### 3.3.6 Petcoke

Petroleum coke has increasingly become an important swing fuel or fuel-blend candidate for a number of utilities in the U.S. Petcoke is a by-product of the oil refining process. There are various grades of pet coke production, with different sulfur, BTU and HGI contents. The fuel has a lot of value in the marketplace because it is a high BTU product (generally around 14,000 BTU), but its value is limited because it also contains very high sulfur content, ranging from 3 % to 6%. Grindability is variable from very soft to very hard (35 – 70 HGI is typical).

Plants with scrubbers can use pet coke and still minimize $SO_2$ emissions, and the fuel is typically blended with coals at these plants. It is also purchased by many cement plants because of its high carbon value. Figure 3-12 shows the increasing deliveries of pet coke to utility plants since 1992.

**Figure 3-12**



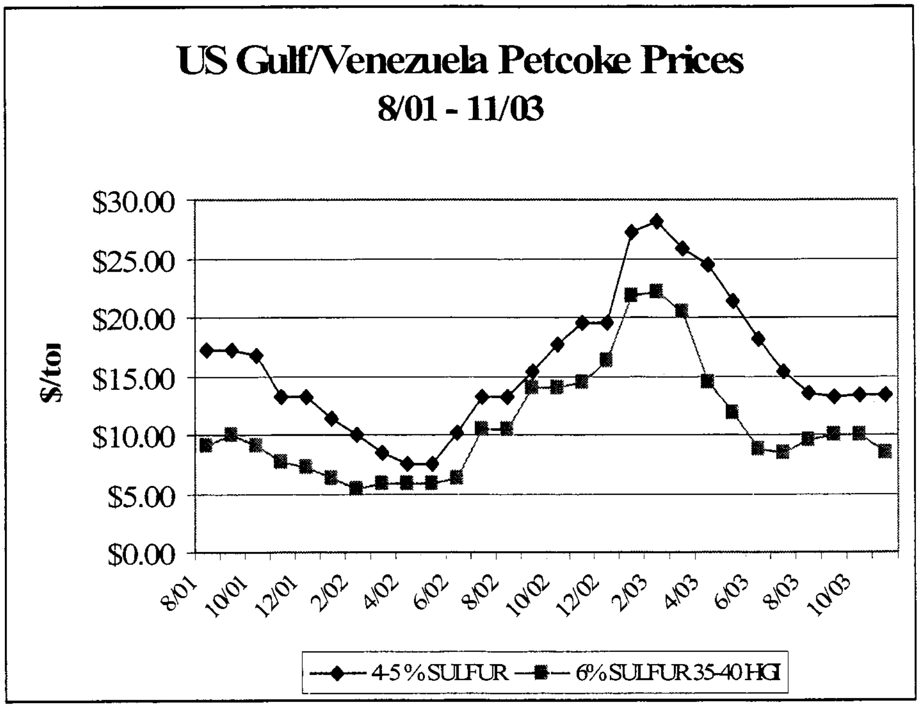

Petcoke has a number of other possible negative impacts on plant operations, ranging from:

- High levels of vanadium and nickel in the ash.
- Corrosion and wear on boiler tubes and equipment.
- Increases of $SO_2$ and $NO_x$ emissions.
- Unburned carbon in the ash, which can increase landfill problems.

Petcoke prices are highly volatile, ranging from very low levels to very high levels, as shown in Figure 3-13. The price of pet coke depends upon a number of factors and prices for other fuels, such as coal.

Since pet coke is a waste-product of the oil refining process, it can literally be given away at any price and refiners will sell for low prices rather than paying storage and environmental cleanup charges. Therefore, the refineries are generally inclined to dump the pet coke to keep it moving. Likewise, because of the negative impacts of burning this fuel, its upward price is capped by coal and gas prices. However, its price generally tends to follow coal prices.

**Figure 3-13**




Prices for pet coke are likely to drop in the near future as higher ocean freight rates will trigger a drop in demand to consumers relying on spot ocean freight rates. Lower demand will soften FOB pricing and higher delivered prices will cause consumers to switch to alternatives such as high sulfur U.S. coal. This does not mean that delivered pet coke prices will drop. Instead, the margins are likely to go to the shipping company instead of the pet coke broker/producers.

Currently, there is an estimated known production of about 30 million tons of world-wide pet coke capacity. This number is almost certainly low as many companies do not report their production or capacity. There are also a number of other reported refinery expansions that will produce additional pet coke supplies in the U.S. Among them are:

- Sunoco is planning to open a new coke plant at Haverhill, Ohio.
- Conoco plans to open its new Wood River refinery near St. Louis in early 2004. This is expected to produce around 300,000 tons of pet coke annually.
- Valero's Texas City coker is expected to produce 1 million tons of pet coke annually, beginning by the end of 2003.
- Venezuela's Hamaca upgrader would add another 1.2 – 1.4 million tons of pet coke by mid year 2004, but it might be postponed until 2005.

Key Issues and Market Drivers for Petcoke

- Principal supplies are available in the U.S. and Venezuela.
- Availability is variable since production is dependent upon refineries' processing of crude oils; i.e. pet coke production is directly related to and dependent upon oil refining.
- Prices are highly variable depending upon supply, demand and quality, typically ranging from $6.00 - $30.00 per ton; most time prices are closer to the low end of this range.
- New production capacity is coming online in the U.S., Venezuela and the Caribbean region.
- Transportation issues and costs may be significant depending upon the location of the refineries (e.g. Houston/US Gulf, Chicago, Venezuela, etc.).
- Some quality characteristics are detrimental to meeting air quality requirements and to plant equipment.
- Low volatile content of pet coke can result in poor flame stability in PC boilers.
- Petcoke can cause low temperature corrosion problems in some PC boilers.
- Blending pet coke with coal can cause higher unburned carbon in fly ash and this can hinder commercial sale of ash.
- Fugitive dust can be a problem when handling pet coke.

**3.3.6.1 JEA Northside:** In 1999 Jacksonville Electric Authority decided to repower its oil and gas-fired Northside generating station to take petroleum coke and coal with funding from the government's Clean Coal Technology program. The circulating fluidized bed conversion was supported with $74 million in federal funding; this represented about 24% of the total project costs of approximately $309 million. The goal was for both of the converted units to consume 100% pet coke under full load. The plant receives solid fuel by water and the coal and pet coke storage is under covered domes. JEA has no strict specifications for pet coke. This allows the buyers to take advantage of low price opportunities across a wide range of specs.

Units 1 and 2 were converted and were scheduled to be commissioned in early 2002; start up was delayed until the Spring of 2002. There were problems with burned bearings at the plant during the initial start up phase (unrelated to fuel type). The units initially began operating on 100% coal. As they converted to a coal/pet coke blend, boiler problems occurred. JEA had purchased pet coke for 2002 delivery at low prices ($8.00 to $9.00 per ton) and were concerned that they would not be able to use it at Northside due to these problems.

In the fall of 2002, Foster Wheeler Ltd. filed a lawsuit for breach of contract against the JEA in Duval County Florida. FW claimed they were "denied the opportunity" to complete work at the utility's Northside station. FW claimed that when JEA started the plant in the Spring/Summer of 2002, they effectively denied FW the opportunity to complete all work on the plant and to fairly demonstrate the CFB technology. To our knowledge this suit has not been settled.

Northside continues to have problems burning 100% pet coke. Recent reports suggest the optimal mix is currently 80% pet coke, 20% Pittsburgh #8 coal. These products apparently react well together. JEA is considering a test of high sulfur Illinois Basin coal later this year as prices for Pitt #8 coal have increased.

JEA still intends to burn 100% pet coke in the units; however there are issues that remain to be resolved. The units currently consume about 1.2 million tons of pet coke and 300,000 tons of Pitt #8 coal per year.

In 2003, delivered prices to Northside ranged between 30 to 47 cents per million Btu for 14,380 Btu, 4% sulfur pet coke. Delivered prices for Pittsburgh #8 coal (13,200 Btu, 2.6% sulfur) ranged between 180 to 190 cents per million Btu during this same period.

## 3.4 COAL TRANSPORTATION

In addition to the specific transportation issues that were discussed for each coal region or country, the following major coal transportation issues exist. The Surface Transportation Board recently ruled in favor of the Norfolk Southern (NS) in its rate case against Duke Energy. In that ruling, the STB allowed NS to charge rates that were approximately 50% higher than Duke's previous contract rates. Carolina Power & Light has a similar case before the STB, and this will be decided in December 2003. If CP&L also loses its case, it could set a precedent for the NS (and possibly the CSX and others) to raise rail rates considerably. This could have a significant impact on future delivered fuel costs for many or all U.S. rail shippers.

International shipping rates have increased substantially due to China's massive construction program. These higher rates will lead to increased costs for Latin American coal for importers without freight coverage. This in turn should create higher demand for high Btu, low sulfur coals from Appalachia, Colorado and Utah. The higher freight rates are expected to last about a year, but could continue for several years if Chinese raw material demand remains strong and if shipping capacity does not increase.

## 3.5 SOLID FUEL PRICE FORECAST

H&A has prepared a delivered price forecast for the period 2006 to 2030 for a generic plant site in central Florida. Table 3-2 presents the forecast for the following fuels and delivery methods:

- PRB Rail Delivery to Florida
- PRB Rail Transfer to Barge for Delivery for Florida Coast
- CAPP Rail Delivery to Florida
- CAPP Barge Delivery to Florida Coast
- ILB Rail Delivery to Florida
- ILB Barge Delivery to Florida Coast
- PITT Rail Delivery to Florida
- PITT Barge Delivery to Florida Coast
- Columbian IMPORT via Vessel to Florida Coast
- PETCOKE (6% S) Vessel Delivery to Florida Coast

Note that the delivery points for the rail and barge/vessel alternatives assume the new generation resource is sited in close proximity to existing rail or has developed a site specific barge/vessel unloading facility. The transfer and subsequent truck delivery of coal to an off-site location will add approximately $4.00/ton to the delivered cost.

Table 3-2 also presents two delivered gas cost forecasts which will be discussed in Section 3.6.

## Table 3-2

## Solid-Fuel Delivered Price Forecast (2006 – 2030)

| | | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | PRB Rail (BN) | $ 2.53 | $ 2.58 | $ 2.63 | $ 2.69 | $ 2.74 | $ 2.79 | $ 2.85 | $ 2.91 | $ 2.97 | $ 3.02 | $ 3.08 | $ 3.15 | $ 3.21 | $ 3.27 | $ 3.34 | $ 3.41 | $ 3.47 | $ 3.54 | $ 3.61 | $ 3.69 | $ 3.76 | $ 3.84 | $ 3.91 | $ 3.99 | $ 4.07 |
| | PRB Rail/Barge (BN) | $ 2.30 | $ 2.34 | $ 2.39 | $ 2.44 | $ 2.48 | $ 2.53 | $ 2.58 | $ 2.63 | $ 2.68 | $ 2.73 | $ 2.78 | $ 2.83 | $ 2.89 | $ 2.94 | $ 3.00 | $ 3.06 | $ 3.12 | $ 3.18 | $ 3.24 | $ 3.30 | $ 3.36 | $ 3.43 | $ 3.49 | $ 3.56 | $ 3.63 |
| | CAPP Rail | $ 2.47 | $ 2.52 | $ 2.57 | $ 2.63 | $ 2.68 | $ 2.73 | $ 2.79 | $ 2.84 | $ 2.90 | $ 2.96 | $ 3.02 | $ 3.08 | $ 3.14 | $ 3.20 | $ 3.26 | $ 3.33 | $ 3.40 | $ 3.46 | $ 3.53 | $ 3.60 | $ 3.68 | $ 3.75 | $ 3.82 | $ 3.90 | $ 3.98 |
| | CAPP Barge | $ 2.24 | $ 2.28 | $ 2.33 | $ 2.37 | $ 2.42 | $ 2.47 | $ 2.51 | $ 2.56 | $ 2.61 | $ 2.66 | $ 2.72 | $ 2.77 | $ 2.82 | $ 2.88 | $ 2.94 | $ 2.99 | $ 3.05 | $ 3.11 | $ 3.17 | $ 3.24 | $ 3.30 | $ 3.36 | $ 3.43 | $ 3.50 | $ 3.57 |
| | ILB Rail | $ 2.00 | $ 2.04 | $ 2.08 | $ 2.13 | $ 2.17 | $ 2.21 | $ 2.26 | $ 2.30 | $ 2.35 | $ 2.39 | $ 2.44 | $ 2.49 | $ 2.54 | $ 2.59 | $ 2.64 | $ 2.70 | $ 2.75 | $ 2.80 | $ 2.86 | $ 2.92 | $ 2.98 | $ 3.04 | $ 3.10 | $ 3.16 | $ 3.22 |
| | ILB Barge | $ 1.84 | $ 1.88 | $ 1.92 | $ 1.95 | $ 1.99 | $ 2.03 | $ 2.07 | $ 2.11 | $ 2.15 | $ 2.19 | $ 2.24 | $ 2.28 | $ 2.33 | $ 2.37 | $ 2.42 | $ 2.46 | $ 2.51 | $ 2.56 | $ 2.61 | $ 2.66 | $ 2.72 | $ 2.77 | $ 2.82 | $ 2.88 | $ 2.93 |
| | Pitt 8 Rail | $ 2.24 | $ 2.28 | $ 2.33 | $ 2.37 | $ 2.42 | $ 2.47 | $ 2.52 | $ 2.57 | $ 2.62 | $ 2.67 | $ 2.73 | $ 2.78 | $ 2.84 | $ 2.89 | $ 2.95 | $ 3.01 | $ 3.07 | $ 3.13 | $ 3.19 | $ 3.26 | $ 3.32 | $ 3.39 | $ 3.46 | $ 3.53 | $ 3.60 |
| | Pitt 8 Barge | $ 2.06 | $ 2.10 | $ 2.14 | $ 2.18 | $ 2.22 | $ 2.27 | $ 2.31 | $ 2.36 | $ 2.40 | $ 2.45 | $ 2.50 | $ 2.55 | $ 2.60 | $ 2.65 | $ 2.70 | $ 2.75 | $ 2.81 | $ 2.86 | $ 2.92 | $ 2.97 | $ 3.03 | $ 3.09 | $ 3.15 | $ 3.21 | $ 3.28 |
| | Colombian Import 2 | $ 1.71 | $ 1.74 | $ 1.78 | $ 1.81 | $ 1.85 | $ 1.89 | $ 1.92 | $ 1.96 | $ 2.00 | $ 2.04 | $ 2.08 | $ 2.12 | $ 2.16 | $ 2.21 | $ 2.25 | $ 2.29 | $ 2.34 | $ 2.39 | $ 2.43 | $ 2.48 | $ 2.53 | $ 2.58 | $ 2.63 | $ 2.68 | $ 2.74 |
| | Petcoke HS | $ 0.74 | $ 0.76 | $ 0.77 | $ 0.79 | $ 0.80 | $ 0.82 | $ 0.83 | $ 0.85 | $ 0.87 | $ 0.88 | $ 0.90 | $ 0.92 | $ 0.94 | $ 0.96 | $ 0.97 | $ 0.99 | $ 1.01 | $ 1.03 | $ 1.05 | $ 1.07 | $ 1.09 | $ 1.12 | $ 1.14 | $ 1.16 | $ 1.18 |
| Gas | RFP Gas | $ 5.43 | $ 4.58 | $ 4.16 | $ 4.31 | $ 4.55 | $ 4.64 | $ 4.76 | $ 4.88 | $ 5.01 | $ 5.13 | $ 5.25 | $ 5.38 | $ 5.50 | $ 5.64 | $ 5.77 | $ 5.90 | $ 6.04 | $ 6.17 | $ 6.31 | $ 6.46 | $ 6.61 | $ 6.76 | $ 6.91 | $ 7.07 | $ 7.24 |
| | Reference Gas | $ 5.15 | $ 5.15 | $ 5.27 | $ 5.40 | $ 5.53 | $ 5.66 | $ 5.80 | $ 5.94 | $ 6.08 | $ 6.22 | $ 6.37 | $ 6.53 | $ 6.68 | $ 6.84 | $ 7.01 | $ 7.18 | $ 7.35 | $ 7.53 | $ 7.71 | $ 7.89 | $ 8.08 | $ 8.28 | $ 8.48 | $ 8.68 | $ 8.89 |

## 3.6 NATURAL GAS PRICE FORECAST

A delivered natural gas price forecast (RFP Gas) based on assumptions provided by Progress in the Hines IV Power Supply RFP document issued in October 2003 is presented in Table 3-3 below. The forecast estimates commodity gas prices will decline from current levels to approximately $3.60/MMBtu in 2008, and then increase at an approximate 2.5 percent rate. A gas cost sensitivity forecast (Reference Gas) was prepared by B&McD by referencing current Henry Hub futures pricing (2004-2007) available on the New York Mercantile Exchange (NYMEX) with an added transportation component equal to the RFP gas forecast. Beyond 2007, the commodity cost for the reference gas was escalated at a constant 2.5% as indicated below. Table 3-3 presents the results of both forecasts side-by-side for comparison. The higher reference gas forecast was used to perform a sensitivity analysis of the benchmark combined cycle resource alternative. As indicated, current futures for natural gas supply remain very strong through 2007 and do not decline below $4.50/MMBtu.

**Table 3-3**

**Natural Gas Delivered Price Forecast (2004 – 2030)**

| | RFP Natural Gas Costs | | | Commodity | Reference Natural Gas Costs | | | |
|---|---|---|---|---|---|---|---|---|
| | Commodity | Transportation | Total | Escalation | Commodity | Transportation | Total | |
| **2004** | | | | | $ 5.45 | $ 0.53 | **$ 5.98** | NYMEX |
| **2005** | | | | | $ 4.75 | $ 0.53 | **$ 5.28** | |
| **2006** | $ 4.88 | $ 0.54 | **$ 5.43** | | $ 4.61 | $ 0.54 | **$ 5.15** | |
| **2007** | $ 4.03 | $ 0.55 | **$ 4.58** | -21.2% | $ 4.60 | $ 0.55 | **$ 5.15** | |
| **2008** | $ 3.60 | $ 0.56 | **$ 4.16** | -10.7% | $ 4.71 | $ 0.56 | **$ 5.27** | |
| **2009** | $ 3.74 | $ 0.57 | **$ 4.31** | 4.0% | $ 4.83 | $ 0.57 | **$ 5.40** | |
| **2010** | $ 3.98 | $ 0.58 | **$ 4.55** | 6.3% | $ 4.95 | $ 0.58 | **$ 5.53** | |
| **2011** | $ 4.05 | $ 0.58 | **$ 4.64** | 1.9% | $ 5.08 | $ 0.58 | **$ 5.66** | |
| **2012** | $ 4.17 | $ 0.59 | **$ 4.76** | 2.8% | $ 5.20 | $ 0.59 | **$ 5.80** | |
| **2013** | $ 4.28 | $ 0.60 | **$ 4.88** | 2.7% | $ 5.33 | $ 0.60 | **$ 5.94** | |
| **2014** | $ 4.40 | $ 0.61 | **$ 5.01** | 2.9% | $ 5.47 | $ 0.61 | **$ 6.08** | |
| **2015** | $ 4.51 | $ 0.62 | **$ 5.13** | 2.3% | $ 5.60 | $ 0.62 | **$ 6.22** | |
| **2016** | $ 4.62 | $ 0.63 | **$ 5.25** | 2.5% | $ 5.74 | $ 0.63 | **$ 6.37** | |
| **2017** | $ 4.74 | $ 0.64 | **$ 5.38** | 2.7% | $ 5.89 | $ 0.64 | **$ 6.53** | |
| **2018** | $ 4.86 | $ 0.65 | **$ 5.50** | 2.4% | $ 6.03 | $ 0.65 | **$ 6.68** | |
| **2019** | $ 4.98 | $ 0.66 | **$ 5.64** | 2.5% | $ 6.19 | $ 0.66 | **$ 6.84** | |
| **2020** | $ 5.10 | $ 0.67 | **$ 5.77** | 2.5% | $ 6.34 | $ 0.67 | **$ 7.01** | |
| **2021** | $ 5.23 | $ 0.68 | **$ 5.90** | 2.4% | $ 6.50 | $ 0.68 | **$ 7.18** | |
| **2022** | $ 5.35 | $ 0.69 | **$ 6.04** | 2.4% | $ 6.66 | $ 0.69 | **$ 7.35** | |
| **2023** | $ 5.47 | $ 0.70 | **$ 6.17** | 2.3% | $ 6.83 | $ 0.70 | **$ 7.53** | |
| **2024** | $ 5.60 | $ 0.71 | **$ 6.31** | 2.4% | $ 7.00 | $ 0.71 | **$ 7.71** | |
| **2025** | $ 5.74 | $ 0.72 | **$ 6.46** | 2.4% | $ 7.17 | $ 0.72 | **$ 7.89** | |
| **2026** | $ 5.88 | $ 0.73 | **$ 6.61** | 2.4% | $ 7.35 | $ 0.73 | **$ 8.08** | |
| **2027** | $ 6.02 | $ 0.74 | **$ 6.76** | 2.4% | $ 7.54 | $ 0.74 | **$ 8.28** | |
| **2028** | $ 6.16 | $ 0.75 | **$ 6.91** | 2.4% | $ 7.72 | $ 0.75 | **$ 8.48** | |
| **2029** | $ 6.31 | $ 0.76 | **$ 7.07** | 2.4% | $ 7.92 | $ 0.76 | **$ 8.68** | |
| **2030** | $ 6.46 | $ 0.77 | **$ 7.24** | 2.4% | $ 8.12 | $ 0.77 | **$ 8.89** | |
| **Escalation** | | 1.5% | | | 2.5% | 1.5% | | |

The reference gas sensitivity based on current Henry Hub futures pricing (2004-2007) is primarily a short-term projection that has been extended throughout the planning period based on a constant escalation assumption. It does not reflect potential supply-side factors that are included in the RFP gas forecast such as the potential import of liquefied natural gas (LNG) supplies that would tend to mitigate the current high domestic gas supply pricing.

A graphical representation of the relationship between the forecasted solid fuel prices and natural gas prices is presented in Figure 3-14.

## 3.7 OVERVIEW

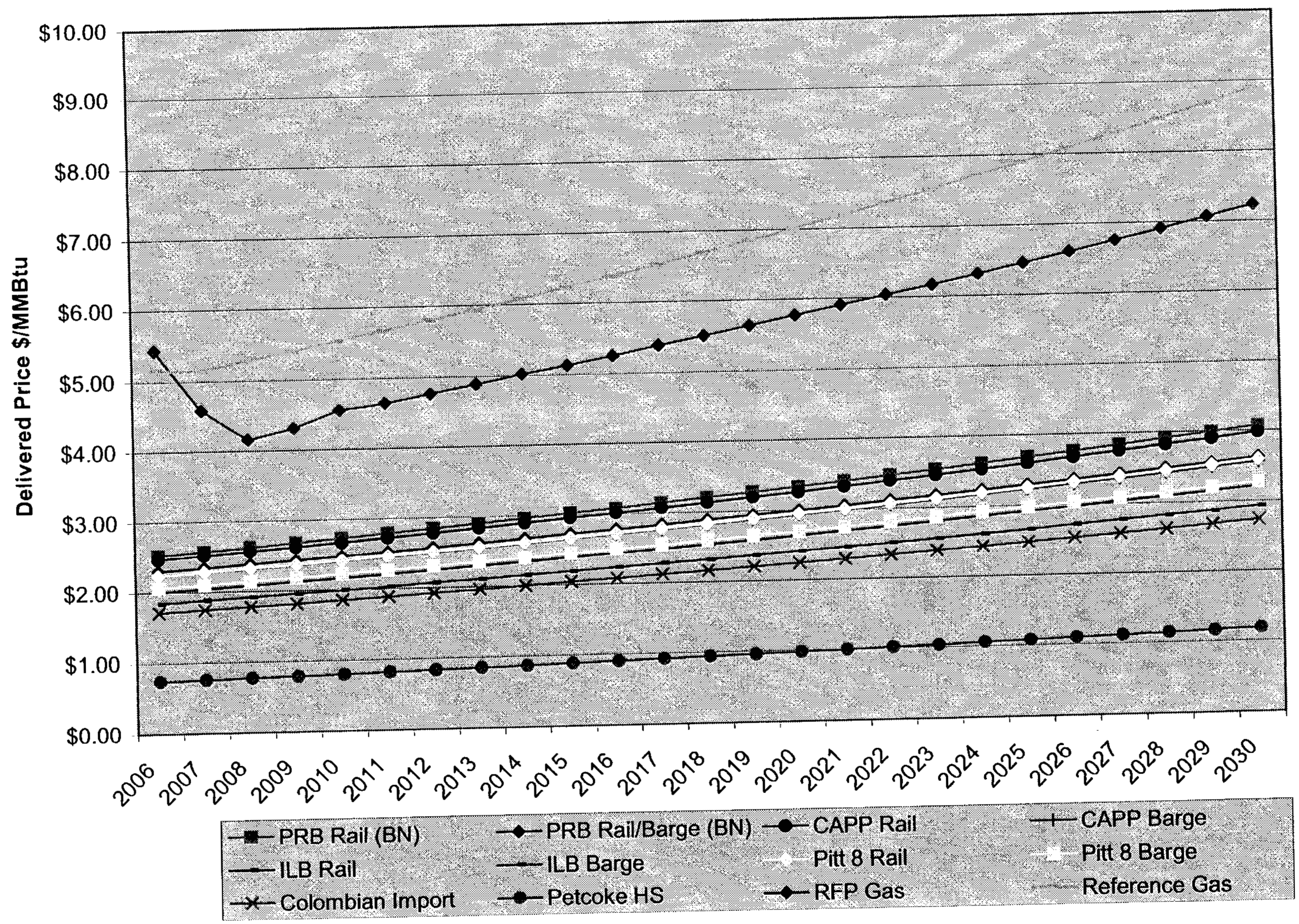
As indicated, the lowest cost fuel alternative on a $/MMBtu basis is high sulfur pet coke delivered from the Gulf region to the Gulf coast of Florida. The next lowest cost solid fuel alternatives are imported coal from Columbia and Illinois Basin coal. For each solid fuel alternative, barge delivery is slightly lower than rail delivery into inland Florida due to lack of competition between rail carriers in Florida. CSX is the dominant rail, and has very little competition beyond the northern areas of Florida. For imported coal, the supply and delivery risks will be higher than sourcing fuel from a domestic supplier.

Each of the following fuel alternatives is evaluated in the economic analysis.

- PRB Rail Delivery to Florida
- CAPP Rail Delivery to Florida
- ILB Rail Delivery to Florida
- PITT Rail Delivery to Florida
- Columbian IMPORT via Vessel to Florida Coast
- PETCOKE (6% S) Vessel Delivery to Florida Coast
- Natural Gas (NG) RFP Forecast
- Natural Gas (NG) Reference Forecast

**Figure 3-14**

**Forecasted Solid Fuel/Natural Gas Prices**



# Section 4

# Economic Analysis

# SECTION 4
# ECONOMIC ANALYSIS

## 4.1 OBJECTIVE

B&McD prepared a number of pro forma economic analyses of various solid fuel project and fuel alternatives. A twenty-year economic analysis was prepared based on the estimated capital costs, performance, fuel costs, and operating costs of each Project alternative. The results of the solid fuel Project alternatives were compared against the estimated costs of a combined cycle expansion of the Hines IV station under the RFP natural gas cost forecast and an alternate gas cost sensitivity.

## 4.2 COAL ASSUMPTIONS & COST ESTIMATES

The following Project estimates and economic assumptions were utilized in the pro forma financial analysis.

| | |
|---|---|
| • Capital Costs including Owner Costs and Contingency | Appendix A |
| • Fuel Cost Assumptions | Table 3-2 |
| • Heat Rate Performance Assumptions | Appendix A |
| | |
| • Operating Assumptions: | |
| Planned Dispatch | 8,016 hours per year (one month planned outage) |
| Forced Outage Rate | 5.0% |
| Overall Capacity Factor | 85.0% |
| | |
| • Financing Assumptions: | |
| Interest Rate | 6.5% |
| Term | 30 years |
| Debt/Equity Percentage | 48%/52% |
| Return on Equity | 12.0% |
| Financing Fees | 0.50% |
| Construction Financing | 48 months |

- O&M Cost Assumptions:

| | |
|---|---|
| Fixed O&M Costs | Appendix A |
| Insurance | 0.3% of EPC Cost per year |
| Property Taxes | 1.0% of EPC Cost per year |
| Variable O&M Costs | Appendix A |
| Transmission Costs | Not Included – Busbar Cost Evaluation |
| Limestone Costs | Included in Variable O&M |
| Emissions Allowances | \$200/ton $SO_2$ Allowance (2003\$) |
| | \$3,000/ton NOx Allowance (2003\$) |

- Economic Assumptions:

| | |
|---|---|
| O&M Inflation | 2.5% per annum |
| Solid Fuel Inflation | 2.0% per annum |
| Solid Fuel Transportation Inflation | 1.9% per annum |
| Discount Rate | 8.2% |
| Effective Tax Rate | 38.58% |
| Book Life | 30 years |

Note that the capital cost estimates presented in Appendix A are escalated to 2010\$. The O&M estimates in Appendix A are presented in 2003\$ and escalated in the pro forma analysis.

## 4.3 COMBINED CYCLE BENCHMARK ASSUMPTIONS

The results of the economic analysis of solid fuel generation alternatives were compared to a benchmark combined cycle alternative based on an expansion of the Hines station with an additional 500 MW 2x1 CCGT plant under two natural gas cost forecasts. The following summarizes the Hines IV benchmark cost assumptions included in the Power Supply RFP issued in October 2003.

| | |
|---|---|
| • Capital Costs | \$280 million (\$560/kW in 2007\$) |
| • Fuel Assumptions | Table 3-2 |
| • Heat Rate Performance Assumptions | 6,775 Btu/kWh (HHV) |

- Operating Assumptions:

| | |
|---|---|
| Overall Capacity Factor | 85.0% for comparative purposes |

- Financing Assumptions:

| | |
|---|---|
| Interest Rate | 6.5% |
| Term | 25 years |
| Debt/Equity Percentage | 48%/52% |
| Return on Equity | 12.0% |
| Financing Fees | 0.50% |
| Construction Financing | 24 months |

- O&M Cost Assumptions:

| | |
|---|---|
| Fixed O&M Costs | $.96/kW-yr plus 48% overheads (2007$) |
| Insurance | 0.3% of EPC Cost per year |
| Property Taxes | 1.0% of EPC Cost per year |
| Variable O&M Costs | $2.88/MWh (2007$) |
| Transmission Costs | Not Included – Busbar Cost Evaluation |
| Emissions Allowances | N/A |

- Economic Assumptions:

| | |
|---|---|
| O&M Inflation | 2.5% per annum |
| Discount Rate | 8.2% |
| Effective Tax Rate | 38.58% |
| Book Life | 25 years |

The benchmark combined cycle cost assumptions above represent a brownfield expansion of the Hines station. An expansion of an existing site will inherently require less capital costs as well as a lower incremental staffing cost than the development of a greenfield site.

## 4.4 ECONOMIC ANALYSIS RESULTS

The economic pro forma analyses were used to determine the busbar cost of power for each alternative. Figure 4-1 presents a graph of the resulting levelized busbar power costs for natural gas and greenfield subcritical PC options over a 20 year planning period covering 2011 to 2030. Figure 4-1 was developed by preparing a project pro forma for each of the alternatives under consideration. The levelized busbar cost represents the fixed energy cost that would be equivalent to an annually escalated busbar cost over 20 years in 2011$.

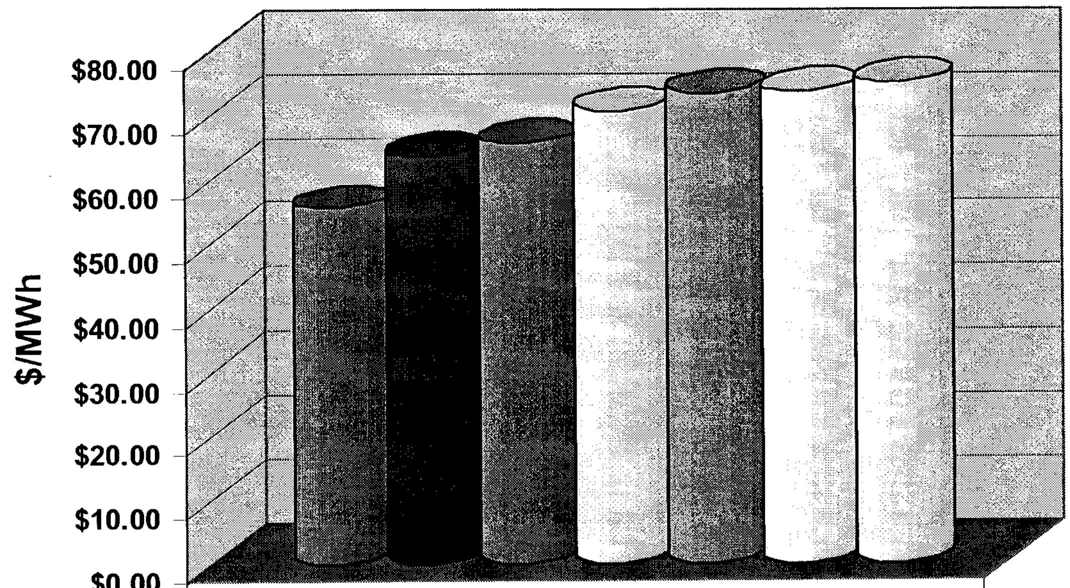
Figure 4-1 presents the comparison of 500 MW greenfield PC units under the various fuel alternatives against the 500 MW combined cycle unit under the RFP gas forecast and the reference gas sensitivity. As indicated, none of the greenfield 500 MW PC unit alternatives resulted in a levelized busbar cost that was lower than the two combined cycle expansion cases. Imported coal and Illinois Basin were the best fuel alternatives for a 500 MW subcritical PC unit. The economic analysis utilizes the delivered costs for imported coals, but does not include a premium for other risk factors, such as foreign political instability and ocean shipping risk. Figure 4-2 presents the annual busbar cost projections of each alternative.

Figure 4-3 presents the comparison of 500 MW greenfield units under the various technology alternatives for the lower cost imported coal and Illinois basin fuel. Pet coke is also considered as a fuel source for a CFB unit in a 100% firing case and a 50%/50% blended case with Illinois basin coal. The results of the analysis in Figure 4-3 indicate that utilizing pet coke as a fuel source in a CFB unit is a cost-effective combination. The 100% fired pet coke alternative is now a lower cost option than the 500 MW combined cycle unit under the reference gas sensitivity. However, firing 100% pet coke is difficult due to operational issues and potential erosion problems. Figure 4-3 also identifies that there is little life cycle cost difference between subcritical and supercritical PC units. Subcritical units have a slightly lower capital cost while supercritical units have slightly better performance. Over a 20 year analysis, the overall costs are very similar. Most utilities selecting supercritical technology are basing the decision on improved emissions performance. Figure 4-3 also includes an IGCC alternative that reflects a differential 10 percent availability penalty compared to PC or CFB technology. As discussed previously, the IGCC technology is not recommended for consideration.

Figures 4-4 through 4-6 present a comparison of different Project sizes for the Illinois basin coal PC Project, the imported coal PC Project, and the CFB Project burning a blend of pet coke and Illinois basis coal. These analyses identify the economies of scale for solid fuel generation alternatives. As indicated, the resulting busbar cost is 8.1% lower for a 1000 MW plant site compared to 500 MW for the Illinois basin coal PC, 9.4% lower for a 1000 MW plant site compared to 500 MW for the imported coal PC, and 9.6% lower for a 1000 MW plant site compared to 500 MW for the CFB units on blended coal.

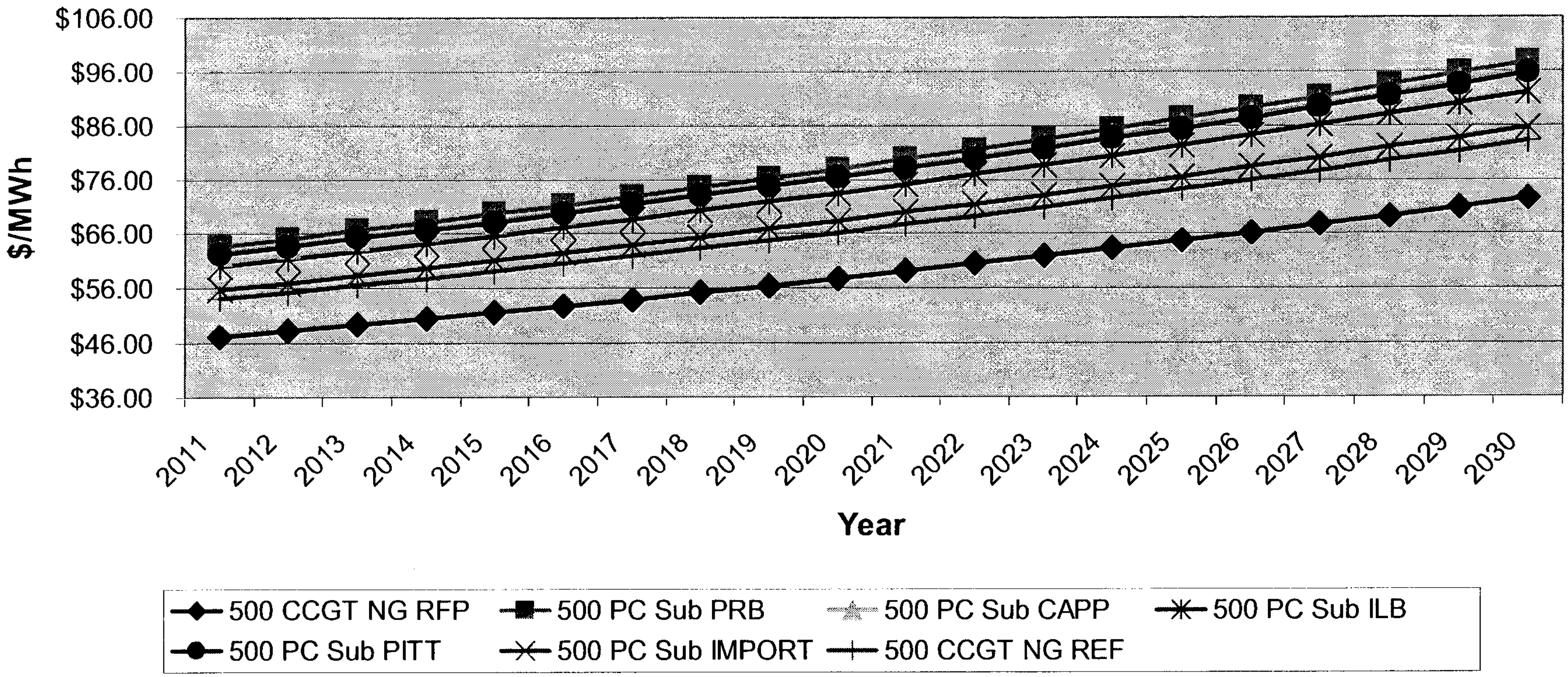
Figure 4-7 demonstrates the significant cost savings that can accrue if a solid fuel generation resource is located at an existing coal generation station. All of the 500 MW brownfield alternatives presented have a lower levelized busbar cost than the 500 MW combined cycle unit under the reference gas sensitivity. The 100% fired pet coke brownfield alternative is a lower cost option than the 500 MW combined cycle unit under the RFP gas forecast, however, firing 100% pet coke is not fully viable. Figure 4-8 presents similar results for a 1000 MW Project at a brownfield location.

**Figure 4-1**
**Levelized 20 Year Busbar Costs**
**500 MW Greenfield PC Unit with Alternative Fuel Sources**

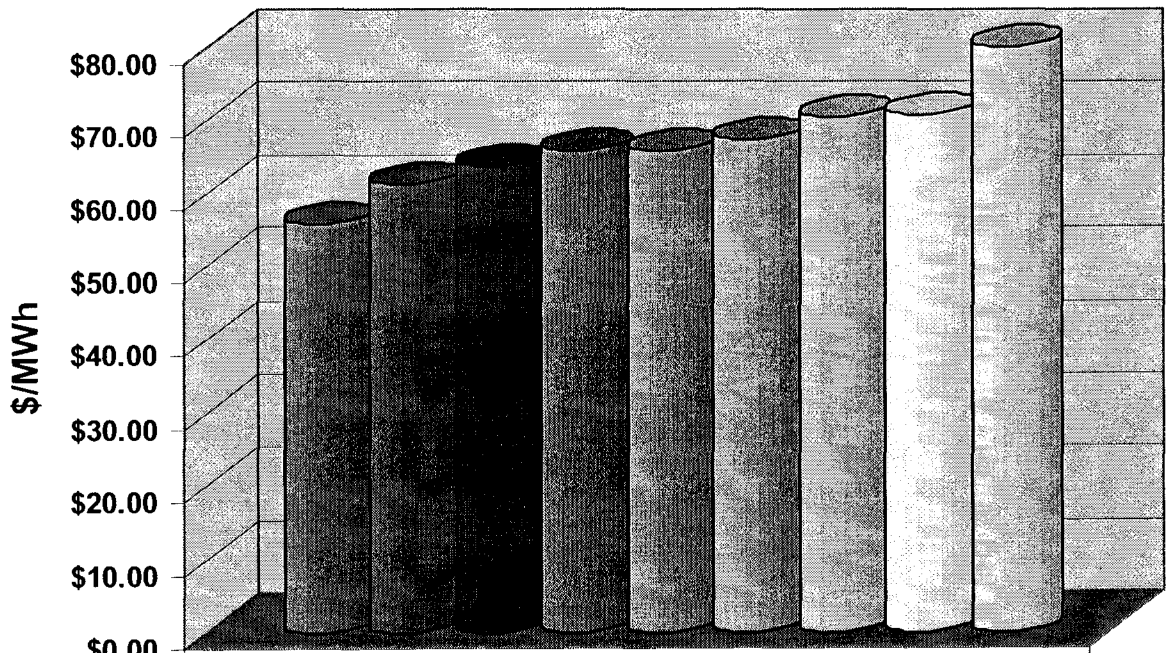



| | Alternatives |
|---|---|
| 500 CCGT NG RFP | $55.61 |
| 500 CCGT NG REF | $63.76 |
| 500 PC Sub IMPORT | $65.80 |
| 500 PC Sub ILB | $70.76 |
| 500 PC Sub PITT | $73.50 |
| 500 PC Sub CAPP | $73.79 |
| 500 PC Sub PRB | $75.06 |

Figure 4-2
Estimated Annual Busbar Costs

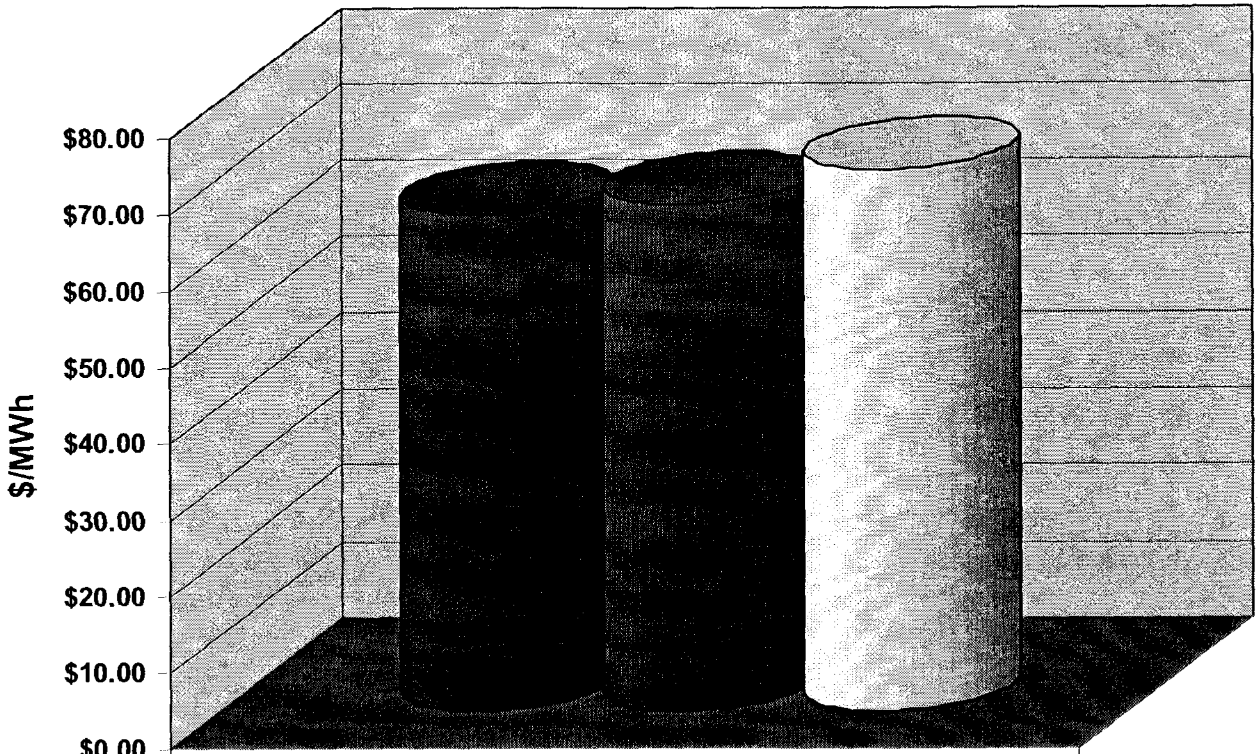


## Figure 4-3
## Levelized 20 Year Busbar Costs
## 500 MW Greenfield Site with Alternative Technologies



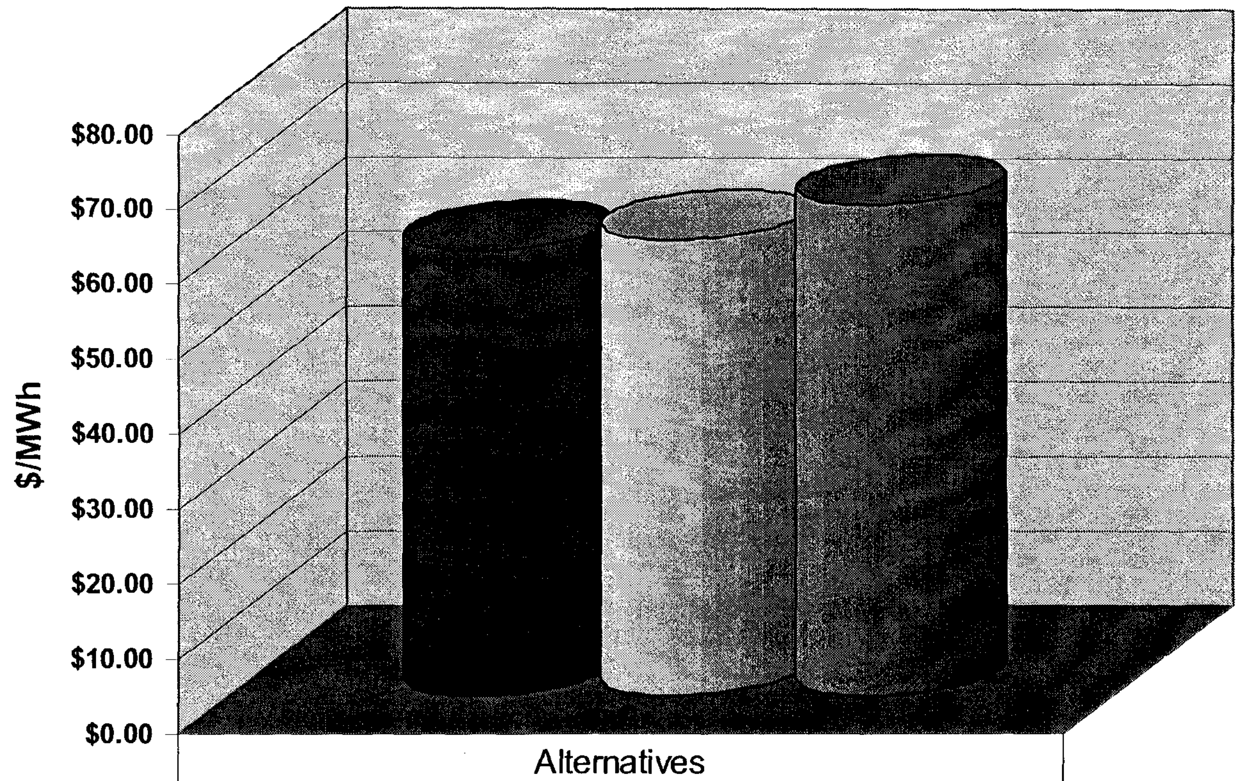

| | Alternatives |
|---|---|
| 500 CCGT NG RFP | $55.61 |
| 500 CFB PETCOKE | $61.26 |
| 500 CCGT NG REF | $63.76 |
| 500 PC Sub IMPORT | $65.80 |
| 500 PC Super IMPORT | $65.79 |
| 500 CFB BLEND | $67.52 |
| 500 PC Super ILB | $70.66 |
| 500 PC Sub ILB | $70.76 |
| 500 IGCC ILB | $81.51 |

**Figure 4-4**
**Levelized 20 Year Busbar Costs**
**Alternative Sizes of Greenfield Subcritical PC Units Burning Illinois Basin Coal**



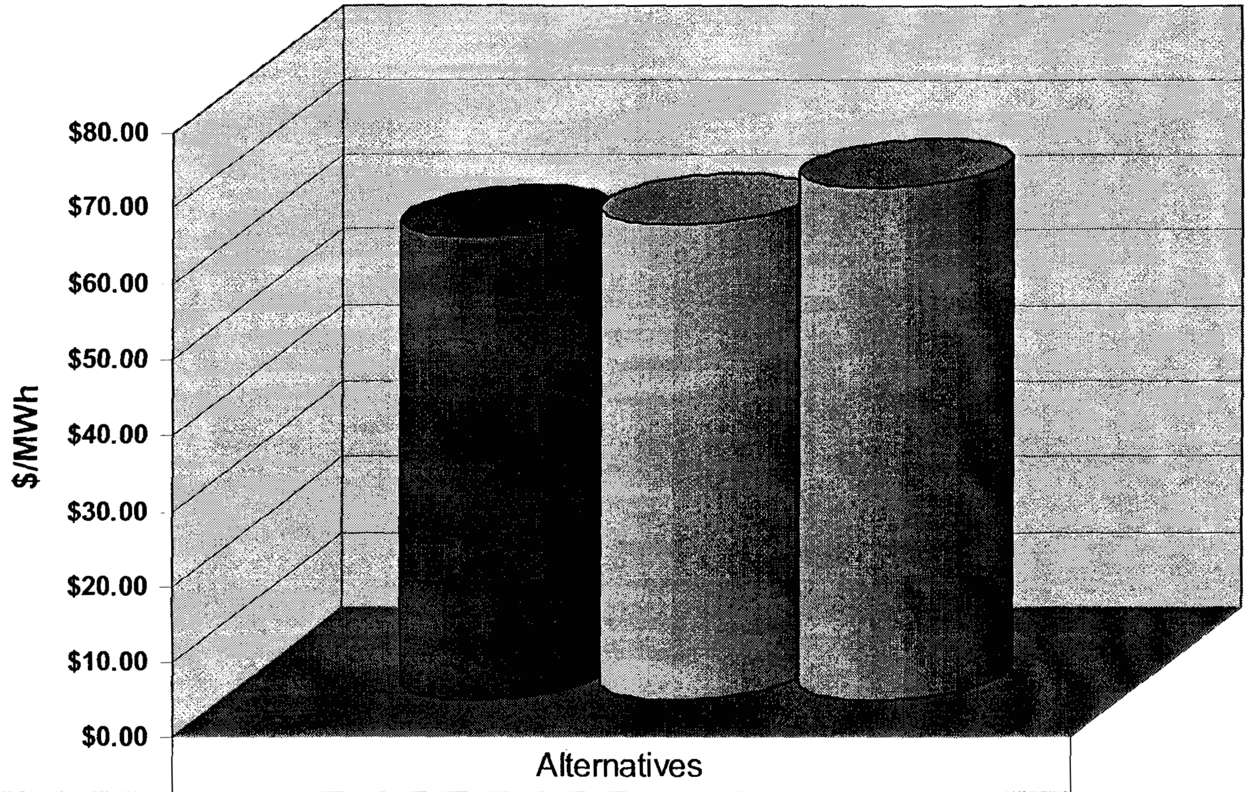

| | Alternatives |
|---|---|
| 1000 PC Sub ILB | $65.01 |
| 750 PC Sub ILB | $66.27 |
| 500 PC Sub ILB | $70.76 |

## Figure 4-5
## Levelized 20 Year Busbar Costs
## Alternative Sizes of Greenfield Subcritical PC Units Buring Imported Coal



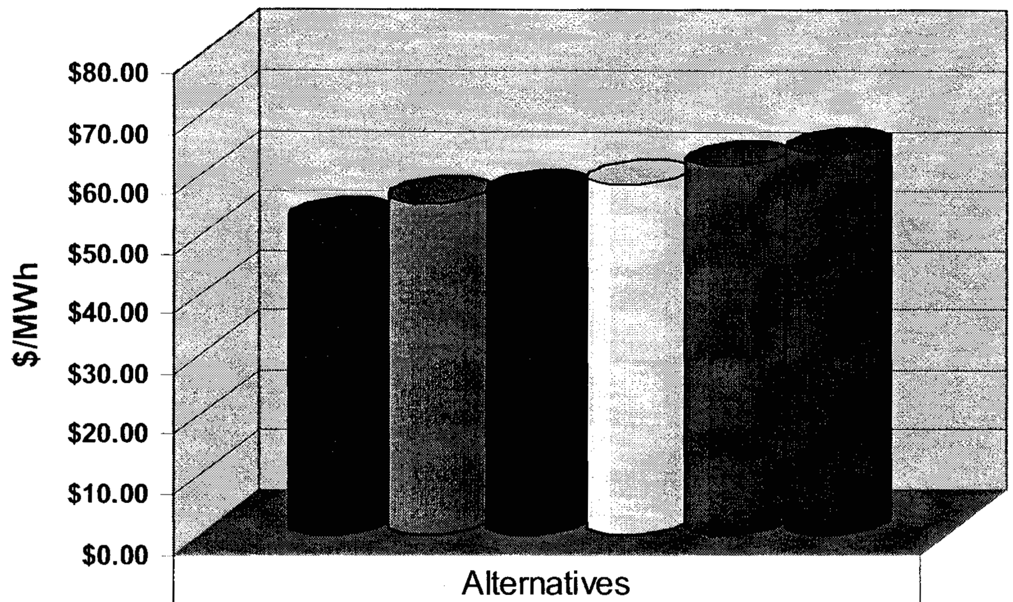

| | Alternatives |
|---|---|
| 1000 PC Sub IMPORT | $59.59 |
| 750 PC Sub IMPORT | $61.04 |
| 500 PC Sub IMPORT | $65.80 |

**Figure 4-6**
**Levelized 20 Year Busbar Costs**
**Alterntive Sizes of Greenfield CFB Units Burning a Blend of Illinois Basin Coal and Petcoke**



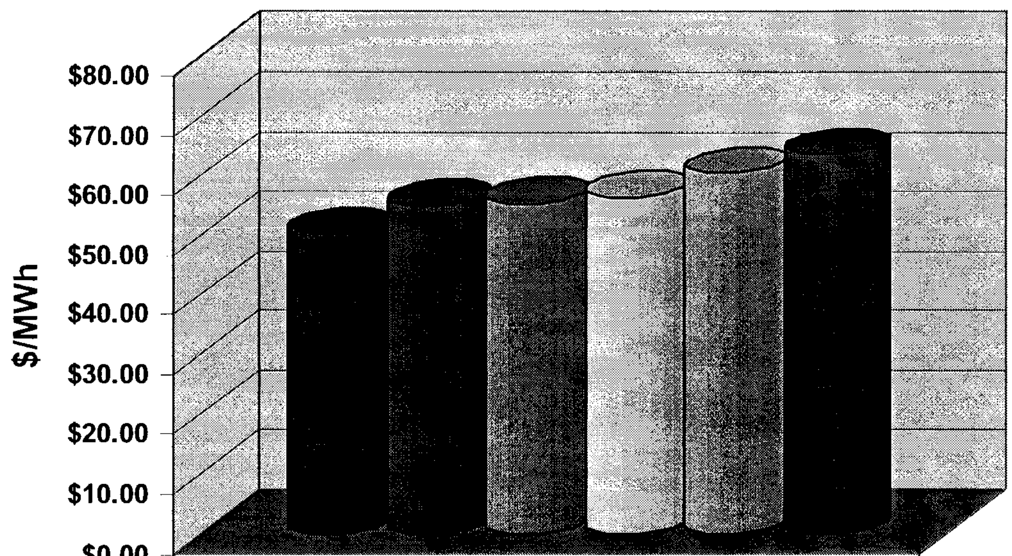

| | Alternatives |
|---|---|
| 1000 CFB BLEND | $61.06 |
| 750 CFB BLEND | $62.58 |
| 500 CFB BLEND | $67.52 |

## Figure 4-7
## Levelized 20 Year Busbar Costs
## 500 MW Brownfield Sites with Alternative Technologies and Fuels




| | Alternatives |
|---|---|
| 500 CFB PETCOKE BRN | $52.31 |
| 500 CCGT NG RFP | $55.61 |
| 500 PC Sub IMPORT BRN | $56.87 |
| 500 CFB BLEND BRN | $58.58 |
| 500 PC Sub ILB BRN | $61.82 |
| 500 CCGT NG REF | $63.76 |

**Figure 4-8**
**Levelized 20 Year Busbar Costs**
**1000 MW Brownfield Sites with Alternative Technologies and Fuels**




| | Alternatives |
|---|---|
| 1000 CFB PETCOKE BRN | $50.45 |
| 1000 PC Sub IMPORT BRN | $55.24 |
| 500 CCGT NG RFP | $55.61 |
| 1000 CFB BLEND BRN | $56.70 |
| 1000 PC Sub ILB BRN | $60.66 |
| 500 CCGT NG REF | $63.76 |

## 4.5 ECONOMIC CONCLUSIONS

Figure 4-9 presents a comparison of overall economic results for feasible solid fuel generation resources to be evaluated by Progress in further siting and preliminary engineering studies. The most cost-effective solid fuel projects incorporate the following characteristics.

- Brownfield site locations that offer infrastructure and operating cost savings are competitive.
- Competitive PC unit fuels are imported Columbian coal and Illinois basin coal. Pet coke can also be blended and co-fired in a PC boiler with Illinois basin coal to take advantage of its lower delivered cost. However, the percentage of pet coke that can be cofired in a PC unit is limited and changing to a different blend requires retuning the boiler. Also, imported coal will have higher risk due to political instability in the source country and ocean shipping risk.
- CFB technology to more fully take advantage of lower delivered costs for pet coke appears advantageous. While burning 100% pet coke in a CFB unit can be operationally challenging, high percentages (i.e., greater than 75%) are being achieved at an existing CFB plant in Jacksonville, Florida. CFB units also offer more fuel flexibility compared to PC technology which can be beneficial to keep long-term fuel costs down.
- Larger unit sizes such as 750 MW will result in improved economics compared to 500 MW blocks for the PC units. Further, larger plant sizes such as 2 x 750 MW will result in improved economics due to reduced capital costs and reduced O&M costs.
- Subcritical and supercritical technologies are both viable, reflect similar life cycle costs, and are selected frequently based on operating preferences and environmental considerations.
- Florida is unique location. Due to the long distance from domestic coal resources and limited transportation competition, the delivered fuel costs of several solid fuel alternatives are high compared to other coal plants in the southeast. Barge or vessel delivery offers slightly lower costs than rail delivery and offers greater fuel flexibility. The possibility of siting a new unit that could generate barge versus rail competition should be pursued.

## 4.6 SENSITIVITY ANALYSIS RESULTS

A sensitivity analysis was prepared for the 1 x 500 MW subcritical PC unit with imported Columbian coal and the 2 x 1 500 MW CCGT with the reference gas cost forecast under the following cases:

- Capital Cost (plus or minus 10%)
- Interest Rate (5.5% and 7.5%)

- Capacity Factor (plus or minus 5%)
- Fuel Cost (plus or minus 10%)
- O&M Costs (plus or minus 10%)

The results of the sensitivity analyses are presented in tornado diagrams in Figure 4-10 and 4-11. A tornado diagram illustrates the range of results for each sensitivity case and its impact on the levelized power cost, and ranks the results from greatest impact to least impact. The sensitivity analysis indicates that capital cost and capacity factor are the two most significant factors affecting the economics of a solid fuel unit. Delivered fuel cost by far has the strongest impact on the overall economics of a combined cycle unit. This is an important result since the market price of natural gas is inherently volatile and nearly impossible for a utility to control over the long term. Hence, many utilities have a renewed interest in coal generation with its more stable fuel costs as means to protect customers from future natural gas market conditions.

Solid fuel generation resources are significantly more capital intensive than gas combined cycle plants, and have a construction period that can be more than twice the length of a combined cycle plant. This results in substantially more capital risk due to interest costs, labor availability and costs, and general inflation. Other risk factors associated with the construction of new solid fuel generation plants include the fact several US boiler manufacturers are currently under financial duress, and the skilled workforce that constructed a number of coal units in the 1970's and 1980's have aged without a significant influx of younger construction workers with similar specialized skills and experience. If a number of new coal units initiate construction within the next decade, the supply of skilled construction workers could be strained. The primary tradeoff for these higher capital risks with a solid fuel generation resource is the long-term stability of coal and other solid fuel alternatives which have few competing uses relative to natural gas that is used by almost all economic sectors including residential heating.

## 4.7 OTHER COST IMPACTS

Figure 4-12 presents the economic results of the following three cost impact cases evaluated for a 500 MW PC unit burning Illinois basin coal.

- Coastal location versus inland
- Dry cooling versus wet
- Zero liquid discharge system

As indicated, each of the three cases results in a cost impact compared to the base case results. The worst impact was for the ZLD system. Due to its increased capital costs and auxiliary power requirements for the treatment system and crystallizer, the life cycle costs are significantly increased. The ACC system also has both capital and performance impacts.

## 4.8 CAPACITY FACTOR SENSITIVITY

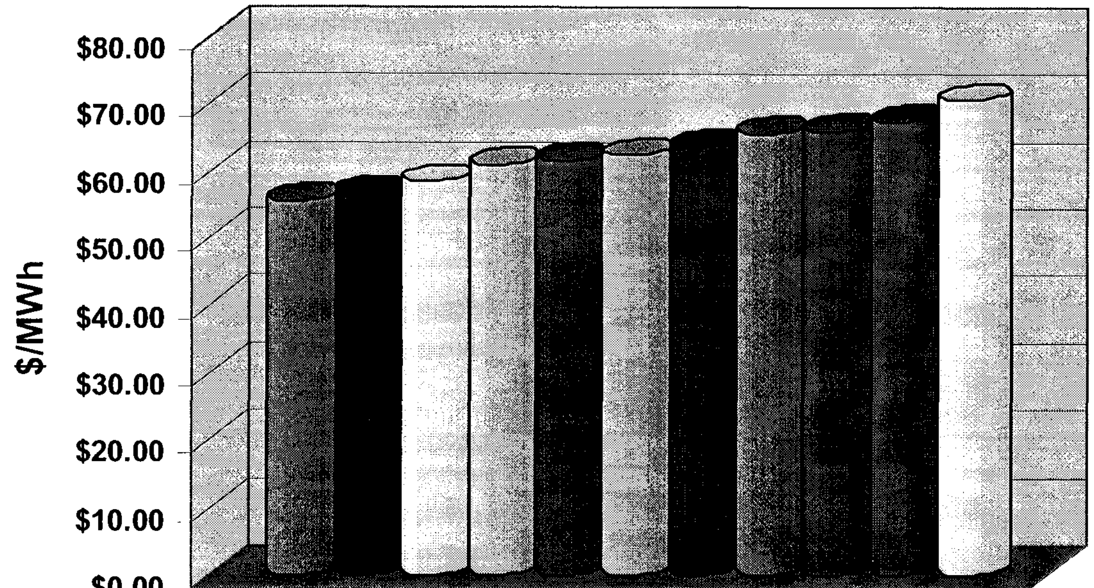
The economic analyses presented in this section assume an 85% capacity factor for both the gas combined cycle benchmark and the solid fuel generation alternatives. This allows a consistent comparison of busbar costs on an energy delivery basis. However, an 85% capacity factor represents a baseload resource, which is typically not the planned or actual dispatch of a gas combined cycle plant. These resources are typically designed and operated as an intermediate resource with capacity factors of 25% to 60%.

Figure 4-13 presents the economic results a 500 MW greenfield PC unit burning imported coal compared to the combined cycle benchmark cases under the RFP gas forecast and the higher reference gas sensitivity across various capacity factors for dispatch. As indicated in Figure 4-13, a combined cycle resource has a clear economic advantage at low and intermediate dispatch levels. The solid fuel resource is only economically competitive under higher dispatch cases representing baseload operations.

## 4.9 FEDERAL INCENTIVES

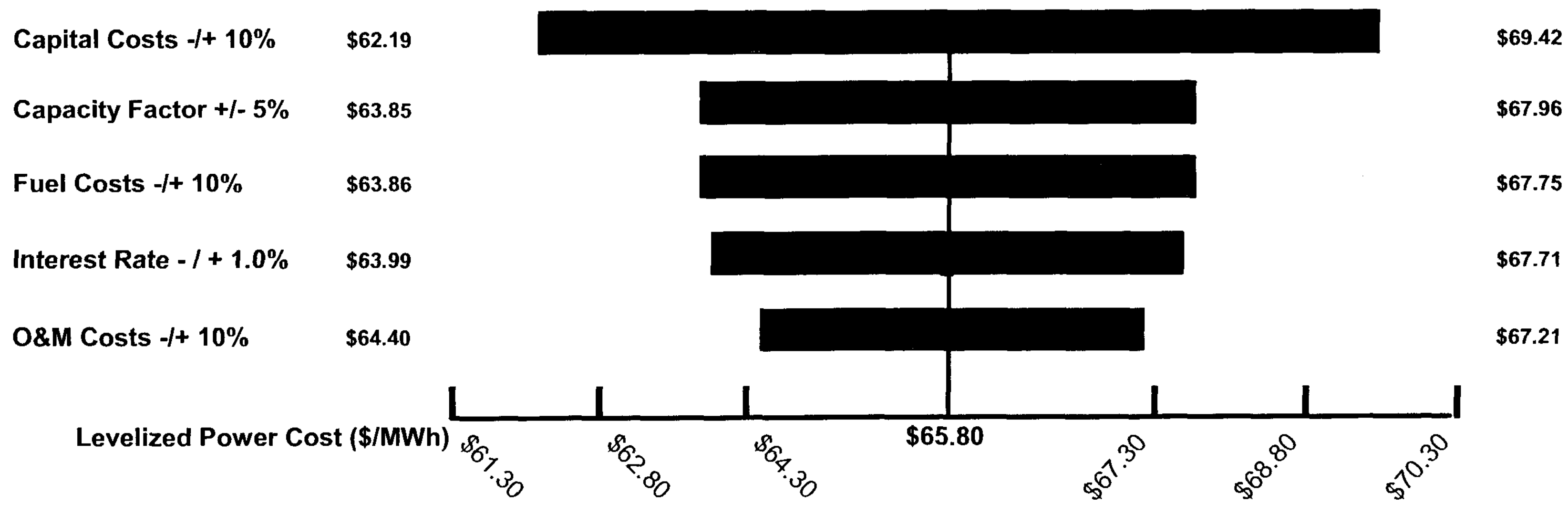
The economic analyses presented do not assume any federal grants, tax incentives, or other programs are used to reduce the economic cost of the solid fuel generation alternatives. In the past, the Federal government has provided funding for various solid fuel projects under its Clean Coal program administered by the Department of Energy. Although there is further funding included in the proposed Energy Policy Act of 2003, the majority of these funds are targeted at the development and implementation of new technologies that can achieve significant reductions in emissions. B&McD does not recommend that Progress consider the implementation of a new technology in order to pursue federal cost sharing at this time.

## Figure 4-9
## Levelized 20 Year Busbar Costs
## Overall Summary of Results




| | Alternatives |
|---|---|
| 500 CCGT NG RFP | $55.61 |
| 500 PC Sub IMPORT BRN | $56.87 |
| 500 CFB BLEND BRN | $58.58 |
| 750 PC Sub IMPORT | $61.04 |
| 500 PC Sub ILB BRN | $61.82 |
| 750 CFB BLEND | $62.58 |
| 500 CCGT NG REF | $63.76 |
| 500 PC Sub IMPORT | $65.80 |
| 750 PC Sub ILB | $66.27 |
| 500 CFB BLEND | $67.52 |
| 500 PC Sub ILB | $70.76 |

# Figure 4-10
## 1 x 500 MW Subcritical PC Unit - IMPORT Coal
## Sensitivity Analysis - Tornado Diagram



# Figure 4-11
## 2 x 1 - 500 MW CCGT Unit (Reference Gas)
## Sensitivity Analysis - Tornado Diagram

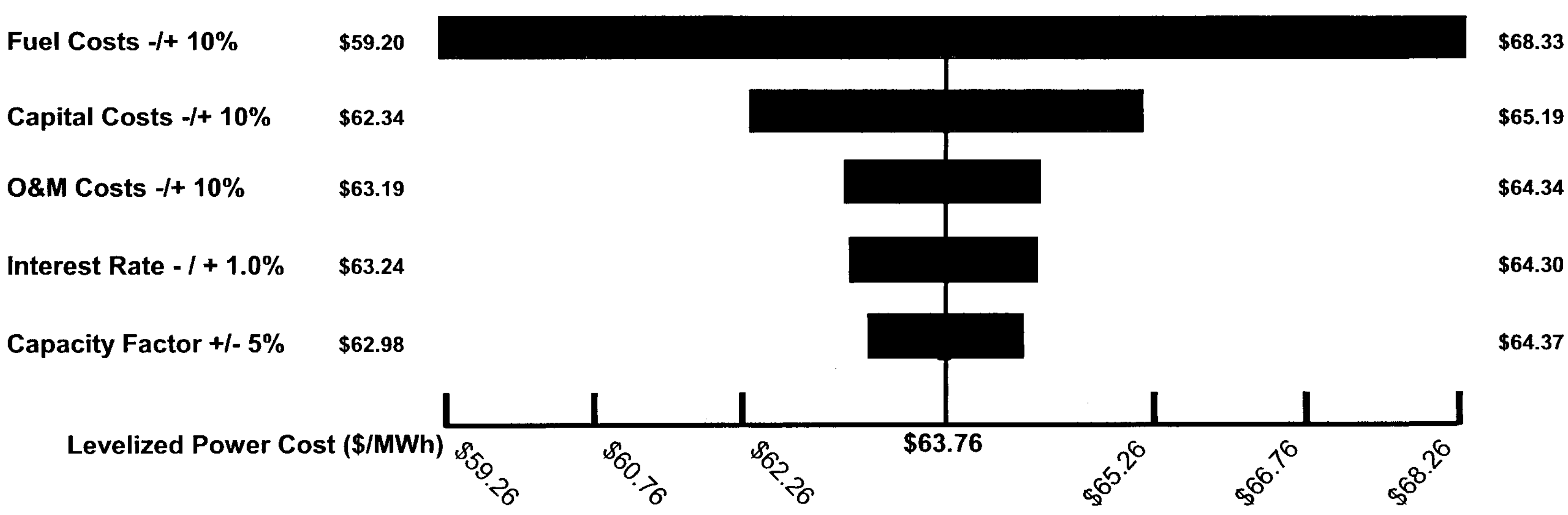
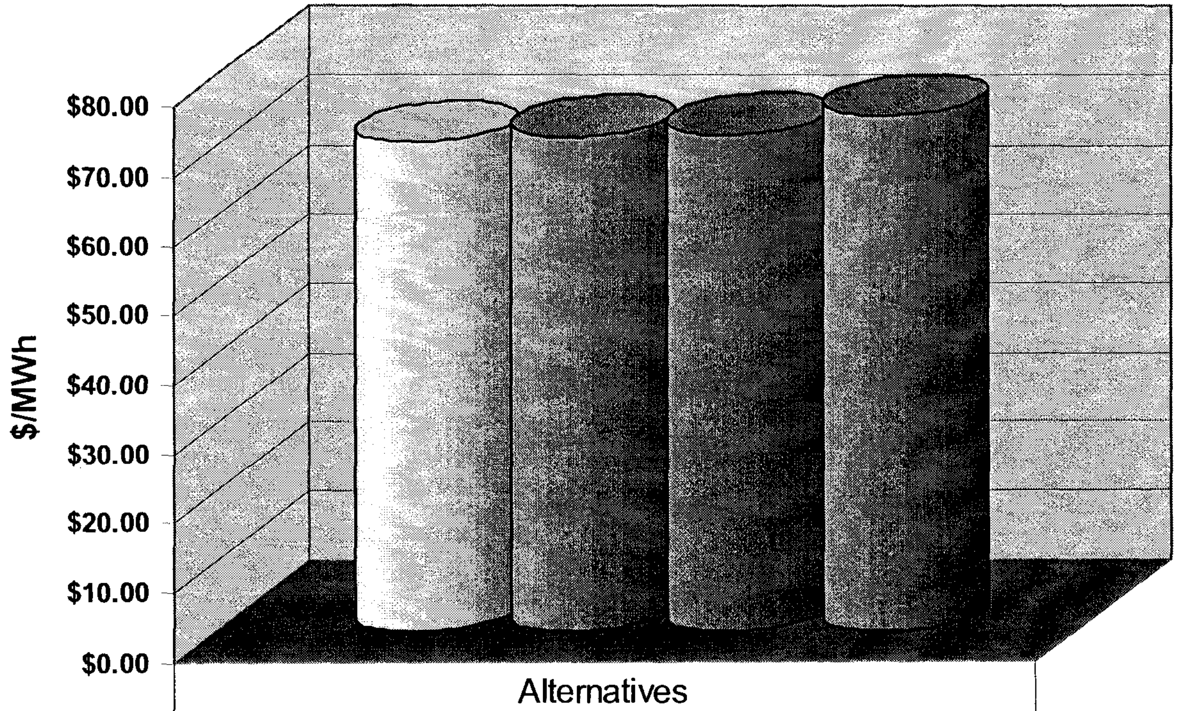
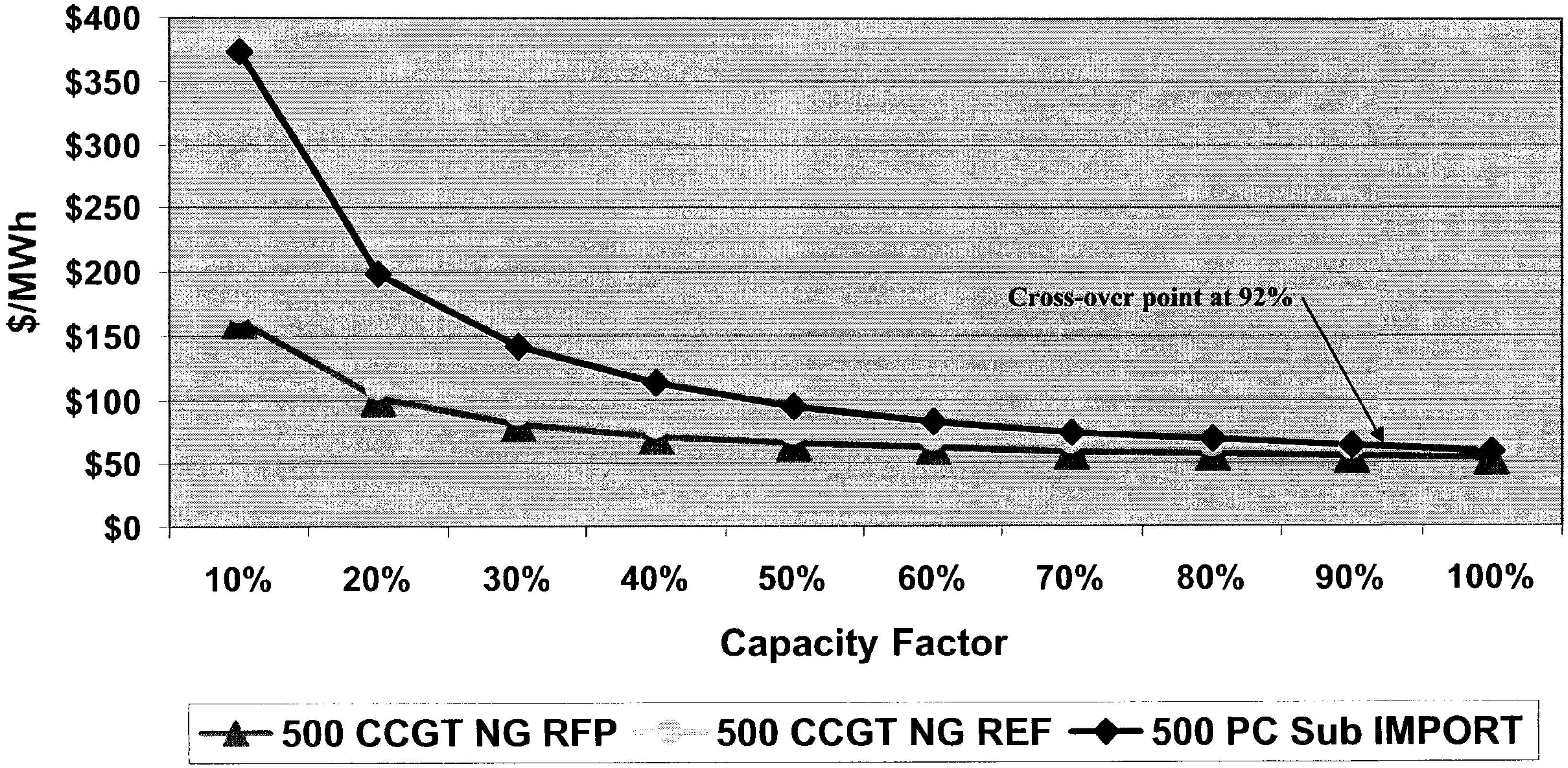


**Figure 4-12**
**Levelized 20 Year Busbar Costs**
**Capital Cost Alternatives for a 500 MW Subcritical PC Unit Burning Illinois Basin Coal**




| | Alternatives |
|---|---|
| 500 PC Sub ILB | $70.76 |
| 500 PC Sub ILB COAST | $71.57 |
| 500 PC Sub ILB DRY | $71.85 |
| 500 PC Sub ILB ZLD | $74.52 |

**Figure 4-13**
**Levelized 20 Year Busbar Costs**
**For Varying Capacity Factors**



# Section 5

# Environmental Permitting Assessment

# SECTION 5
# ENVIRONMENTAL PERMITTING ASSESSMENT

## 5.1 OBJECTIVE

B&McD prepared a permit matrix and preliminary environmental permitting schedule for a proposed solid fuel generation resource to be sited and developed in Florida.

## 5.2 PERMIT MATRIX

Appendix C contains a preliminary permit matrix listing each of the major environmental permits anticipated to be required for the Project. The matrix includes the following information.

- Permit/Clearance Required
- Description
- Regulatory Entity Issuing Permit
- Contact
- Prerequisites/Submittal Information
- Application Fee
- Preparation Timeframe
- Acquisition Timeframe
- Key Issues/Risks
- Permit Approval Requirements

## 5.3 PERMIT SCHEDULE

Appendix C also contains a preliminary environmental permit/clearance schedule. The application and approval of the Project's regulatory certificate and air permit will be the long lead permits to secure before construction of the Project can commence. Note that transmission line approvals/permits and regulatory approvals may also impact the implementation schedule in addition to the permits for the generating station if new transmission lines are required to support the facility.

The permit schedule reflects an approximate 30 month period from the time preliminary engineering for permit preparation is initiated until the site certification is issued. The schedule does not include pre-application ambient air monitoring which may be required for a period of up to twelve months.

## 5.4 BEST AVAILABLE CONTROL TECHNOLOGY

An evaluation of the anticipated Best Available Control Technology (BACT) requirements and selected control technologies for a new solid fuel plant located in Florida was performed. The results of this evaluation are included in the table in Appendix B for the different fuels and combustion technologies under evaluation. For comparison purposes, the emissions limits for two recently permitted solid fuel facilities in the southeast are listed below in Table 5-1.

**Table 5-1**

**Emission Limits Set for Recently Permitted Facilities (lb/MMBtu)**

| Facility | Unit Type | Fuel Type | $SO_2$ | $NO_x$ | $PM_{10}$ | CO | VOC |
|---|---|---|---|---|---|---|---|
| JEA Northside | CFB | Bituminous/ Pet Coke | 0.15 | 0.09 | 0.011 | 0.13 | 0.005 |
| Santee Cooper | PC | Bituminous/ Pet Coke | 0.30 | 0.08 | 0.018 | 0.02 | N/A |

### 5.4.1 Proposed Multi-Pollutant Control Legislation

In the 108$^{th}$ Congress, several congressional bills have been introduced that would establish multi-pollutant control regulations for fossil fuel fired power plants. Each of these proposals address, as a minimum, emissions of $NO_x$, $SO_2$, and mercury. Proposed $NO_x$ reductions range between 59% and 75% by as early as 2008. Proposed $SO_2$ reductions range between 59% and 80% by as early as 2008. Proposed mercury reductions range between 29% and 90% as early as 2008. These proposed multi-pollutant control bills would require amendments to the Clean Air Act (CAA) and would affect existing and pending regulations.

**5.4.1.1 Clear Skies Act:** On February 14, 2002, President Bush introduced the Clear Skies Initiative, his administration's approach to reducing emissions of $SO_2$, $NO_x$, and mercury from power plants. On July 29, 2002, President Bush's Clear Skies Initiative was introduced to the 107$^{th}$ Congress as the Clear Skies Act of 2002. A modified version of the legislation was reintroduced to the 108$^{th}$ Congress on February 27, 2003. On November 10, 2003, the latest version of the Clear Skies Act was introduced to Congress by Senator Inhofe (R-OK) and Senator Voinovich (R-OH). This latest version of the Clear Skies Act is the chairman's mark of the bill introduced to Congress in February 2003.

The Clear Skies Act sets nationwide emission caps for $SO_2$, $NO_x$, and mercury and proposes a market-based, cap-and-trade approach similar to that used by the EPA's Acid Rain Program for $SO_2$. Emission allowance trading will be allowed from one unit to another and from one plant to another under the Clear Skies Act. Under the chairman's mark of the Clear Skies Act, a pool of $SO_2$, $NO_x$, and mercury allowances is created for new units that commence operation each year.

**5.4.1.2 Clean Power Act:** On June 27, 2002, the Senate Environment and Public Works Committee of the 107th Congress adopted the Clean Power Act of 2002, Senator Jeffords's (I-VT) proposal to reduce emissions of $SO_2$, $NO_x$, mercury, and $CO_2$ from electric generating facilities. The Clean Power Act of 2002 is a substitute for the Clean Power Act of 2001, introduced by Senator Jeffords on March 15, 2001. The Clean Power Act was reintroduced to the 108th Congress on February 12, 2003 as the Clean Power Act of 2003.

Under the Clean Power Act, a majority of the $SO_2$, $NO_x$, and $CO_2$ allowances would be initially allocated to:

- Consumers and Households
- Transition Assistance (for workers, communities, and electricity-intensive product manufacturers economically affected by the bill)
- Renewable Electricity Generating Units, Efficiency Projects, and Cleaner Energy Sources
- Biological and Geologic Carbon Sequestration Projects

Only 10% of the $SO_2$, $NO_x$, and $CO_2$ allowances would be allocated to existing sources in 2009. This percentage would decrease by 1% each year until 2018, when only 1% of the $SO_2$, $NO_x$, and $CO_2$ allowances would be reserved for existing sources. In 2019, no allowances would be allocated to existing sources. The total number of allowances under the Clean Power Act is also scheduled to decrease annually. Under this bill, the total number of $SO_2$, $NO_x$, and $CO_2$ emission allowances would be decreased each year by the number of tons of each pollutant emitted by small units (less than 15 MW) in the second preceding year and by any additional amount deemed necessary by the EPA Administrator to protect public health or the environment.

The Clean Power Act proposes to set a mercury emission limit for individual units based on 0.0000227 lbs mercury/MWh. Trading of mercury allowances would not be permitted, except between multiple units at a single plant site.

**5.4.1.3 Clean Air Planning Act:** On October 18, 2002, the Clean Air Planning Act of 2002 was introduced to Congress by Senator Carper (D-DE), Senator Chafee (R-RI), Senator Breaux (D-LA), and Senator Baucus (D-MT). The Clean Air Planning Act is proposed multi-pollutant control legislation to reduce emissions of $SO_2$, $NO_x$, mercury, and $CO_2$ from electric generating facilities. The Clean Air Planning Act was reintroduced to the 108th Congress on April 9, 2003 as the Clean Air Planning Act of 2003.

Under the proposed Clean Air Planning Act, the EPA Administrator, in consultation with the Secretary of Energy, must set aside a reserve of $SO_2$, $NO_x$, mercury, and $CO_2$ allowances to be allocated to new affected units that start-up each year. The number of allowances reserved for new units would be based on projections of electricity output for new units. As more new units are built every year, the number of allowances left over for existing units will decrease.

**5.4.1.4 Impact on the New Progress Energy Unit:** As the Clear Skies Act, Clean Power Act, and Clean Air Planning Act are still just proposed bills, the ultimate requirements of future multi-pollutant control legislation cannot be precisely determined. However, the Clear Skies Act is strongly supported by the current administration and is the most representative of the probable impacts of future multi-pollutant control legislation.

Under the Clear Skies Act, the new Progress Energy unit would be required to hold $SO_2$, $NO_x$, and mercury allowances to cover its emissions. As the latest version of the Clear Skies Act proposes to create a pool of allowances for new units, the new unit would be allocated a certain number of allowances. It is not possible to precisely determine the number of allowances that would be allocated to the new Progress Energy unit under the Clear Skies Act, as it is not known how many other units will be receiving allowances from the new unit allowance pool. Depending on the number of allowances allocated to the new unit in relation to its emissions, the new unit may be required to purchase additional allowances to cover its emissions, or an emissions reduction from an existing source under the same ownership would be required to offset the emissions from the new unit.

In addition to creating an emissions cap-and-trade program, the Clear Skies Act would establish the following New Source Performance Standards (NSPS) for new coal-fired units (including IGCC units):

- $SO_2$ – 2.0 lb/MWh
- $NO_x$ – 1.0 lb/MWh
- $PM_{10}$ – 0.20 lb/MWh

- Mercury – 0.015 lb/GWh

### 5.4.2 Ozone Standard and Fine Particulate Standard

On July 18, 1997, the EPA finalized rules to phase out the 1-hour ozone National Ambient Air Quality Standard (NAAQS) of 0.12 ppm (235 $\mu g/m^3$) and replace it with an 8-hour standard of 0.08 ppm (157 $\mu g/m^3$). This final rulemaking also included a revision to the existing particulate matter (PM) standards to include the addition of NAAQS for $PM_{2.5}$ (particles with diameters of 2.5 μm or less). The EPA added an annual $PM_{2.5}$ standard of 15 $\mu g/m^3$ and a 24-hour $PM_{2.5}$ standard of 65 $\mu g/m^3$ to the existing $PM_{10}$ NAAQS. After years of legal obstacles, the EPA is currently implementing the $PM_{2.5}$ and 8-hour ozone NAAQS.

On December 17, 2003, EPA Administrator Mike Leavitt signed a proposed regulation to reduce $SO_2$ and $NO_x$ emissions from electric utilities. Both $SO_2$ and $NO_x$ are precursors of $PM_{2.5}$, and ozone is created via photochemical reactions involving $NO_x$. Under the proposed Interstate Air Quality Rule (IAQR), the EPA is requiring certain states, including Florida, to reduce $SO_2$ and $NO_x$ emissions from electric utilities in order to bring certain areas into compliance with the $PM_{2.5}$ and 8-hour ozone NAAQS. The IAQR is a call to 29 eastern states and the District of Columbia to revise their State Implementation Plans (SIPs). The IAQR is similar to the 1998 $NO_x$ SIP call, but the emission reductions under the IAQR would apply year-round. The proposed regulations would achieve some of the same goals as the latest version of the Clear Skies Act, but would not require action by Congress.

The IAQR proposes an $SO_2$ and $NO_x$ emissions cap-and-trade program to be implemented by the affected States. The emission reductions would occur in two phases, with compliance dates in 2010 and 2015. The goal of the IAQR is to make the individual state rules consistent, so that interstate trading of $SO_2$ and $NO_x$ allowances will be possible. The EPA would provide systems for tracking of all allowance accounts and transactions.

For the first phase of the IAQR (2010), annual $SO_2$ budgets for individual states would be based on a 50% reduction in the total number of $SO_2$ allowances allocated in the state under the existing Acid Rain Program for the years 2010 and beyond. For the second phase of the IAQR (2015), the reduction would be 65%. For the first phase of the IAQR (2010), annual $NO_x$ budgets for individual states would be based on an emission rate of 0.15 lb/MMBtu and the maximum aggregate annual heat input from all utility sources in the state for the period from 1999 through 2002. For the second phase of the IAQR (2015), the emission rate would be 0.125 lb/MMBtu.

The IAQR would not set specific emission limits for the new Progress Energy unit. However, the new unit would be required to hold $SO_2$ and $NO_x$ allowances under the IAQR. As the IAQR proposes state-by-state $SO_2$ and $NO_x$ budgets and requires states to allocate emission allowances among affected sources in the state, the new unit may not receive any $SO_2$ or $NO_x$ allowances. The unit would be required to purchase allowances, or an emissions reduction from an existing source under the same ownership that holds allowances under the IAQR would be required to offset the emissions from the new unit. Similarly, a new unit that is built today would be subject to the EPA's existing Acid Rain Program, but would receive no $SO_2$ allowances under the program. In addition to meeting BACT emission limits, the new unit would be required to purchase $SO_2$ allowances or an $SO_2$ emissions reduction from an existing source under the same ownership would be required to offset the emissions from the new unit.

### 5.4.3 Mercury MACT

On December 15, 2003, EPA Administrator Mike Leavitt signed the Utility Mercury Reductions Proposal to reduce mercury emissions from electric utilities. In this proposed rule, the EPA is taking comments on two proposed options for regulating mercury emissions from electric utilities. Only one of the two options will be finalized.

Option 1 is to regulate mercury emissions from electric utility steam generating units under Section 112 of the Clean Air Act Amendments (CAAA) of 1990. Section 112 of the CAA mandates that maximum achievable control technology (MACT) for mercury be applied. MACT requires that the emissions standard for a new source cannot be less stringent than the emission control that is achieved in practice by the best controlled similar source. Under the mercury MACT, emissions trading is not permitted and each unit will have to maintain compliance on a stand-alone basis. Emissions averaging between multiple units at a single plant site will be allowed.

Option 2 is to regulate mercury emissions from electric utility steam generating units under Section 111 of the CAA. In doing this, EPA is rescinding its December 2000 determination that mercury should be regulated under Section 112 of the CAA. Under Section 111, mercury would be regulated by establishing a combination of NSPS for new sources and Emissions Guidelines for existing sources. The NSPS limits would be the same as the MACT limits for new sources in Option 1. The emission guidelines for existing sources would be based on an emissions cap-and-trade program designed to achieve the same nationwide mercury emission caps as proposed by the latest version of the Clear Skies Act: 34 tons in 2010 and 15 tons in 2018.

Regardless of which mercury regulation option is finalized, the impacts on new units (including the new Progress Energy unit) will be the same. The mercury emission limits that would be set for new coal-fired units under both Utility Mercury Reductions options are listed in Table 5-2.

**Table 5-2**
**Mercury Emission Limits Set for New Units by the Utility Mercury Reductions Proposal**

| Fuel Category | Mercury Emission Limit[1] |
|---|---|
| Bituminous Coal | $6 \times 10^{-6}$ lb/MWh |
| Subbituminous Coal | $20 \times 10^{-6}$ lb/MWh |
| IGCC Units | $20 \times 10^{-6}$ lb/MWh |

[1]Emission limits are 12-month rolling averages

The EPA plans to finalize the Utility Mercury Reductions proposal by December 15, 2004. A unit that commences operation after the final rule is published in the Federal Register will be required to comply with the rule upon start-up.

### 5.4.4 On-Going NSR Litigation

On-going New Source Review (NSR) litigation is not anticipated to impact the emission limits set for the new Progress Energy unit. NSR litigation is focused on utilities that are suspected of violating the EPA's NSR program by making modifications to existing units without going through the NSR process. By receiving a Prevention of Significant Deterioration (PSD) permit for the construction of the new unit, and complying with the emission limits set in that permit, the new unit will be meeting the requirements of the EPA's NSR program.

## 5.5 ENVIRONMENTAL SENSITIVITIES

Figure 5-1 presents the results of an environmental sensitivity based on assumed emission allowance costs under a future multi-pollutant legislation scenario for the 500 MW greenfield PC unit burning Illinois basin coal. Note that the relative economic impacts presented for this single solid fuel technology alternative are representative of the impacts on other technologies evaluated.

The base case includes the following emission allowance costs:

| | |
|---|---|
| Base Case | |
| $SO_2$ Allowances | - \$200/ton (2003\$) |
| $NO_x$ Allowances | - \$3000/ton (2003\$) |

Currently in Florida, a solid fuel generation project would only be required to secure $SO_2$ allowances to operate. The inclusion of a $NO_x$ allowance cost reflects a conservative assumption that $NO_x$ emissions may be subject to restrictions under the proposed Interstate Air Quality Rule (IAQR). The IAQR proposes an $SO_2$ and $NO_x$ emissions cap-and-trade program to be implemented as discussed above.

Case 1 assumes the following emission allowance costs:

| | |
|---|---|
| Case 1 | |
| $SO_2$ Allowances | - \$200/ton (2003\$) |
| $NO_x$ Allowances | - N/A |

Case 1 reflects current requirements in Florida and is lower than the base case assumptions.

Case 2 assumes the following emission allowance costs:

| | |
|---|---|
| Case 2 | |
| $SO_2$ Allowances | - \$600/ton (2003\$) |
| $NO_x$ Allowances | - \$5,000/ton (2003\$) |
| Hg Allowances | - \$30,000/lb (2003\$) |

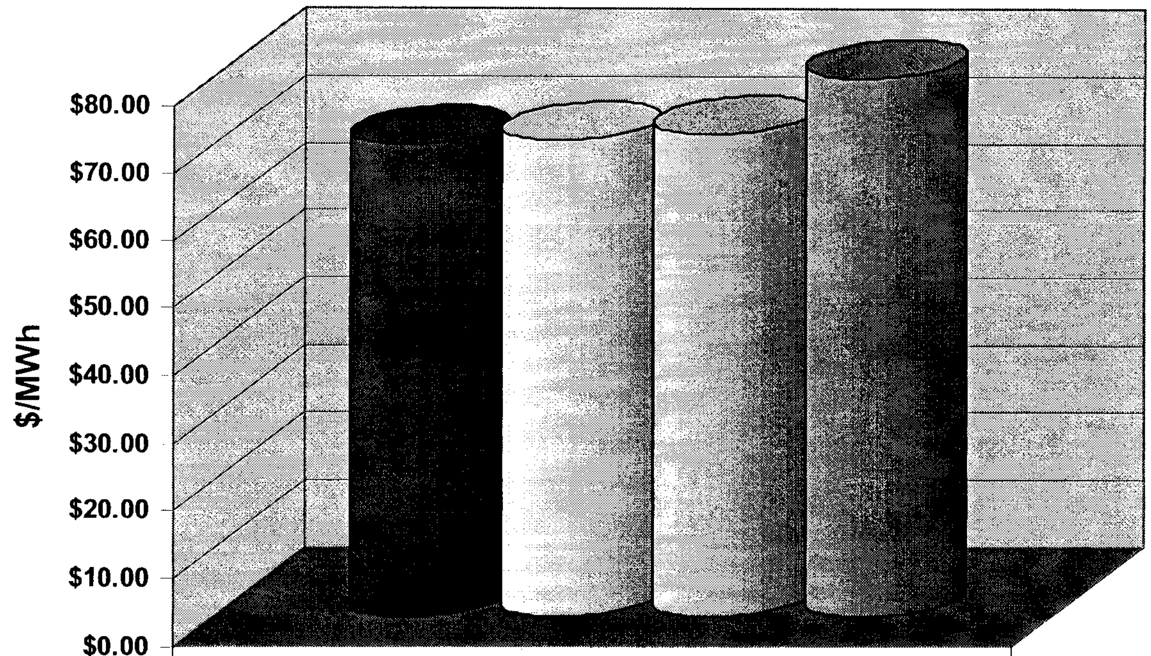
Case 2 reflects a future multi-pollutant legislation scenario which results in a cap-and-trade program for the three pollutants. As indicated in Figure 5-1, these allowance costs would increase the overall busbar cost by approximately 1.3%.

Case 3 is a worst case scenario and includes a $CO_2$ tax with the following emission allowance costs:

| | |
|---|---|
| Case 3 | |
| $SO_2$ Allowances | - \$600/ton (2003\$) |
| $NO_x$ Allowances | - \$5,000/ton (2003\$) |
| Hg Allowances | - \$30,000/lb (2003\$) |
| $CO_2$ Allowance/Tax | - \$10/ton (2003\$) |

As indicated in Figure 5-1 for Case 3, a carbon or $CO_2$ tax can significantly impact the cost of a solid fuel generation resource.

**Figure 5-1**
**Levelized 20 Year Busbar Costs**
**Emissions Allowance Alternatives for a 500 MW Subcritical PC Unit Burning Illinois Basin Coal**




| | Alternatives |
|---|---|
| 500 PC Sub ILB CASE 1 | $70.13 |
| 500 PC Sub ILB BASE | $70.76 |
| 500 PC Sub ILB CASE 2 | $71.71 |
| 500 PC Sub ILB CASE 3 | $82.13 |

# Section 6

# Siting Considerations

# SECTION 6
# SITING CONSIDERATIONS

## 6.1 OBJECTIVE

A specific site location for a potential solid fuel generation resource has not been identified as part of this Feasibility Study. However, B&McD has evaluated the general site requirements for a solid fuel plant located in Florida and this section provides an overview of siting considerations.

## 6.2 EXISTING COAL UNITS IN FLORIDA

Table 6-1 at the end of this section identifies the existing coal generation resources in Florida with a capacity greater than 100 MW. As indicated, there are presently 32 different units with a total generating capacity of almost 13,000 MW. The majority of these units were brought on-line prior to 1990, and a number of the units are currently more than 30 years old. The most recent two units are the CFB units commissioned by Jacksonville Electric Authority at the Northside Station in 2002. The units burn a combination of pet coke and bituminous coal. Fuel supply information available on the other existing coal units in Florida indicates that bituminous coal is used at the other plants as well.

Figure 6-1 at the end of this section illustrates the location of the units in Florida. Note that the vast majority of plants are sited near rail lines or bulk unloading facilities, or both.

## 6.3 SITING CRITERIA

Some of the key factors that should be considered by Progress in siting a solid fuel generation resource should include:

- Control Area
- Fuel Delivery Infrastructure
- Transmission Infrastructure
- Urban Areas and Ozone Maintenance Areas
- Class I Areas
- Site Acreage Requirements
- Water Availability
- Brownfield Locations

## 6.4 CONTROL AREA

Since the solid fuel generation plant will serve as a cost-effective source of baseload energy for Progress' retail and wholesale customers, it would be preferable to locate the generation resource within the Progress control area. This would tend to minimize transmission constraints from delivering energy from the source to the load. In addition, the construction of a new generation resource is a tremendous economic development project with significant new job creation for construction and operations, and local economic benefits in the form of tax payments and the purchase of local goods and services to support the construction and operation of the Project.

Figure 6-2 at the end of this section identifies the different electric control areas in Florida including Progress which is primarily located in central Florida.

## 6.5 FUEL DELIVERY INFRASTRUCTURE

Fuel costs represent the single largest ongoing expenditure for a solid fuel generation resource. It is critical that a new plant be sited with fuel delivery economics strongly evaluated. The economic analysis in Section 4 demonstrated that due to Florida's distance from domestic coal resources, and little competition among rail lines in the state, delivered fuel costs cause the overall economics of solid fuel plants in Florida to be comparable to gas-fired combined cycle units, even in an environment of relatively high gas costs.

Figure 6-3 at the end of this section identifies the major rail lines located in Florida, and the existing ports that have dry bulk unloading capabilities.

The economic analysis for the domestic coal resources (PRB, Illinois Basin, Appalachian) was based on a delivered fuel cost reflecting a plant site in central Florida located in close proximity to an existing rail line. If the coal had to be offloaded from rail and delivered by truck to a plant site, the delivered cost would increase by over $4.00/ton. Over the life-cycle of a solid fuel plant, this makes it very cost effective to site near existing rail, or construct a rail spur to serve the plant and eliminate the need for truck transfer and delivery. As indicated in Figure 6-1, the majority of existing coal units are sited in proximity of existing major rail lines.

There are additional intra-state rail lines not reflected on Figure 6-3. These rail lines may also represent suitable alternatives for siting, but the delivered fuel cost will reflect an additional charge for transfer of the railcars from a major carrier to an intra-state carrier for final delivery.

The economic analysis for the imported coal and pet coke was based on a delivered fuel cost reflecting a plant site on the coast in central Florida with a Project specific unloading facility. Domestic coals (PRB, Illinois Basin, Appalachian) could also be delivered via barge to a coastal location, and based on current rail rates, this delivery method is a slightly lower cost than rail delivery.

The best alternative is to site or develop the capability to receive fuel from either rail or barge/vessel. This would enable Progress to ensure competition between the two delivery modes on a continuing basis. The Crystal River Station has both barge and rail capabilities.

## 6.6 TRANSMISSION INFRASTRUCTURE

Fuel represents the single largest ongoing input and electricity is the primary output of the generation resource. Siting near adequate transmission infrastructure is a key criterion to minimize costs and environmental impacts. The routing, development, permitting and construction of new high voltage transmission lines is as difficult as siting and constructing a solid fuel generation resource. The assessment of transmission infrastructure should include not only the adequacy of the system for interconnection, but also the ability to secure firm transmission without significant system upgrades.

Figure 6-4 at the end of this section identifies the major 230-kV and 500-kV transmission system facilities in Florida.

## 6.7 URBAN AREAS AND OZONE MAINTENANCE AREAS

Urban development areas are generally avoided when siting a power generation resource, particularly a solid fuel resource, due to lack of available land, inconsistent land use, proximity to sensitive receptors, and potential for significant public opposition. There may be acceptable site locations within existing industrial use land classifications, and the potential to site in an existing urban area should not be excluded outright. However, due to the space requirements of a new solid fuel plant, it is frequently difficult to identify a suitable site.

Another significant consideration to siting a facility in urban areas are the ozone maintenance areas in Florida. Figure 6-5 at the end of this section identifies the major urban areas and air quality ozone maintenance areas in Florida. The existence of ozone maintenance areas and their potential impact on project economics would have to be considered in the potential siting of a solid fuel resource.

## 6.8 CLASS I AREAS

Class I areas are federally protected wilderness areas and national parks under which visibility impacts due to regional haze must be minimized. Figure 6-6 at the end of this section identifies the location of the following four Class I areas that are in or near to Florida and will need to be considered in the siting effort.

- Everglades National Park (southern Florida)
- Chassahowitzka Wilderness Area (Gulf Coast north of Tampa)
- St. Marks Wilderness Area (Northeast Florida Gulf Coast)
- Okefenokee Wilderness Area (Southeastern Georgia)

A 100-kilometer buffer area is reflected around each of these Class I areas. This does not imply that a solid fuel project could not be sited within the buffer area, but the closer the resource is sited to a Class I area, the higher likelihood of visibility impacts which may prevent the facility from being permitted. The specific visibility impacts will be technology and fuel dependent along with meteorological wind patterns that may contribute to a visibility impact. It is likely that any plant site within 200-kilometers of a Class I area will be scrutinized, with 100-km representing a higher risk of impact. The 200-kilometer buffer would essentially include most of the land area in Florida.

## 6.9 SITE ACREAGE REQUIREMENTS

Included in Appendix D is a site layout for the plant based on a 2 x 500 MW pulverized coal units. The layout includes a rail loop for solid fuel delivery and a landfill sized for a 30 year Project life. The landfill was sized using the fuel with the highest ash content to represent the greatest landfill area required. This layout shown requires 600 acres of land. Other technologies will change the components and arrangement of structures included in the powerblock area, but will not materially change the total site acreage requirement. The site layout attached does not include any on-site water storage; therefore, if on-site water storage is required, additional land will be required.

## 6.10 OVERVIEW

Figure 6-7 at the end of this section presents an overview map of the above siting considerations. Other factors that can be important criteria in a siting effort include water availability and the potential to utilize an existing brownfield location.

Potential water resources to be evaluated in a siting study for cooling purposes would include the following:

- Groundwater
- Surface water
- Public water
- Reuse of effluent
- Seawater

Steam cycle makeup water sources would also include the above with the general exception of treatment plant effluent and seawater. The use of a dry cooling system would eliminate the need for cooling water, but not steam cycle makeup water requirements. The use of a dry cooling system would also increase the capital cost of the Project and result in decreased performance.

An evaluation of potential water resources was not included in this initial Feasibility Study.

The economic analysis highlighted the significant capital and operating cost benefits that can accrue if a new generation resource is sited at an existing plant site (brownfield location) as opposed to a new site (greenfield location). Reduced operating costs are available due to shared staffing among the existing and new resource. Capital cost savings are available if existing infrastructure can be utilized. Brownfield site locations, particularly existing coal plant sites, should be a priority in a siting evaluation.

Additional environmental factors to be addressed include proximity to state parks and recreational resource areas, proximity to cultural resources, impacts on threatened and endangered species habitats, and impacts to wetlands.

Note that the overview presented in Figure 6-7 is not intended to recommend any specific candidate site locations for evaluation. It primarily illustrates that siting a new solid fuel generation resources may represent a balance among a number of different factors, and it can be difficult to identify a site that fully meets all of the requisite criteria. Frequently, cost and environmental tradeoffs will be evaluated.

# Table 6-1

Florida Coal Fired Plants
Greater Than 100 MW

| Plant Name | Type | Unit # | Online Year | Capacity MW | Heat Rate (Btu/kWh) | Primary Fuel |
|---|---|---|---|---|---|---|
| Big Bend | STEAM | 1 | 1970 | 446 | 9473 | BITUMINOUS COAL |
| Big Bend | STEAM | 2 | 1973 | 446 | 9539 | BITUMINOUS COAL |
| Big Bend | STEAM | 3 | 1976 | 446 | 9554 | BITUMINOUS COAL |
| Big Bend | STEAM | 4 | 1985 | 486 | 9498 | BITUMINOUS COAL |
| Cedar Bay Generating Co., L.P. | STEAM | 1 | 1994 | 285 | NA | BITUMINOUS COAL |
| Central Power and Lime Incorp (CEPOLI) | STEAM | 1 | 1988 | 125 | NA | BITUMINOUS COAL |
| Crist | STEAM | 6 | 1970 | 370 | 10500 | BITUMINOUS COAL |
| Crist | STEAM | 7 | 1973 | 578 | 10100 | BITUMINOUS COAL |
| Crystal River | STEAM | 1 | 1966 | 459 | 9760 | BITUMINOUS COAL |
| Crystal River | STEAM | 2 | 1969 | 545 | 9340 | BITUMINOUS COAL |
| Crystal River | STEAM | 4 | 1982 | 770 | 9420 | BITUMINOUS COAL |
| Crystal River | STEAM | 5 | 1984 | 770 | 9270 | BITUMINOUS COAL |
| Deerhaven | STEAM | 2 | 1981 | 251 | 10200 | BITUMINOUS COAL |
| Gannon | STEAM | 1 | 1957 | 125 | 10699 | BITUMINOUS COAL |
| Gannon | STEAM | 2 | 1958 | 125 | 10760 | BITUMINOUS COAL |
| Gannon | STEAM | 3 | 1960 | 180 | 10263 | BITUMINOUS COAL |
| Gannon | STEAM | 4 | 1963 | 188 | 10118 | BITUMINOUS COAL |
| Gannon | STEAM | 5 | 1965 | 239 | 9546 | BITUMINOUS COAL |
| Gannon | STEAM | 6 | 1967 | 446 | 9787 | BITUMINOUS COAL |
| Indiantown Cogeneration Facility | STEAM | 1 | 1995 | 330 | NA | BITUMINOUS COAL |
| Lansing Smith (GUPC) | STEAM | 1 | 1965 | 150 | 10200 | BITUMINOUS COAL |
| Lansing Smith (GUPC) | STEAM | 2 | 1967 | 190 | 10300 | BITUMINOUS COAL |
| McIntosh (LALW) | STEAM | 3 | 1982 | 364 | 10005 | BITUMINOUS COAL |
| Northside | CFB | 1 | 2002 | 298 | 9615 | PETCOKE/COAL |
| Northside | CFB | 2 | 2002 | 323 | 12659 | PETCOKE/COAL |
| Polk | IGCC | 1 | 1996 | 326 | NA | BITUMINOUS COAL |
| Seminole (SECI) | STEAM | 1 | 1984 | 715 | 10000 | BITUMINOUS COAL |
| Seminole (SECI) | STEAM | 2 | 1985 | 715 | 10000 | BITUMINOUS COAL |
| St. Johns River Power | STEAM | 1 | 1987 | 679 | 9175 | BITUMINOUS COAL |
| St. Johns River Power | STEAM | 2 | 1988 | 679 | 9254 | BITUMINOUS COAL |
| Stanton Energy Center | STEAM | 1 | 1987 | 465 | 9762 | BITUMINOUS COAL |
| Stanton Energy Center | STEAM | 2 | 1996 | 465 | NA | BITUMINOUS COAL |
| **Number of Units** | | **32** | **Total Capacity** | **12,972** | | |

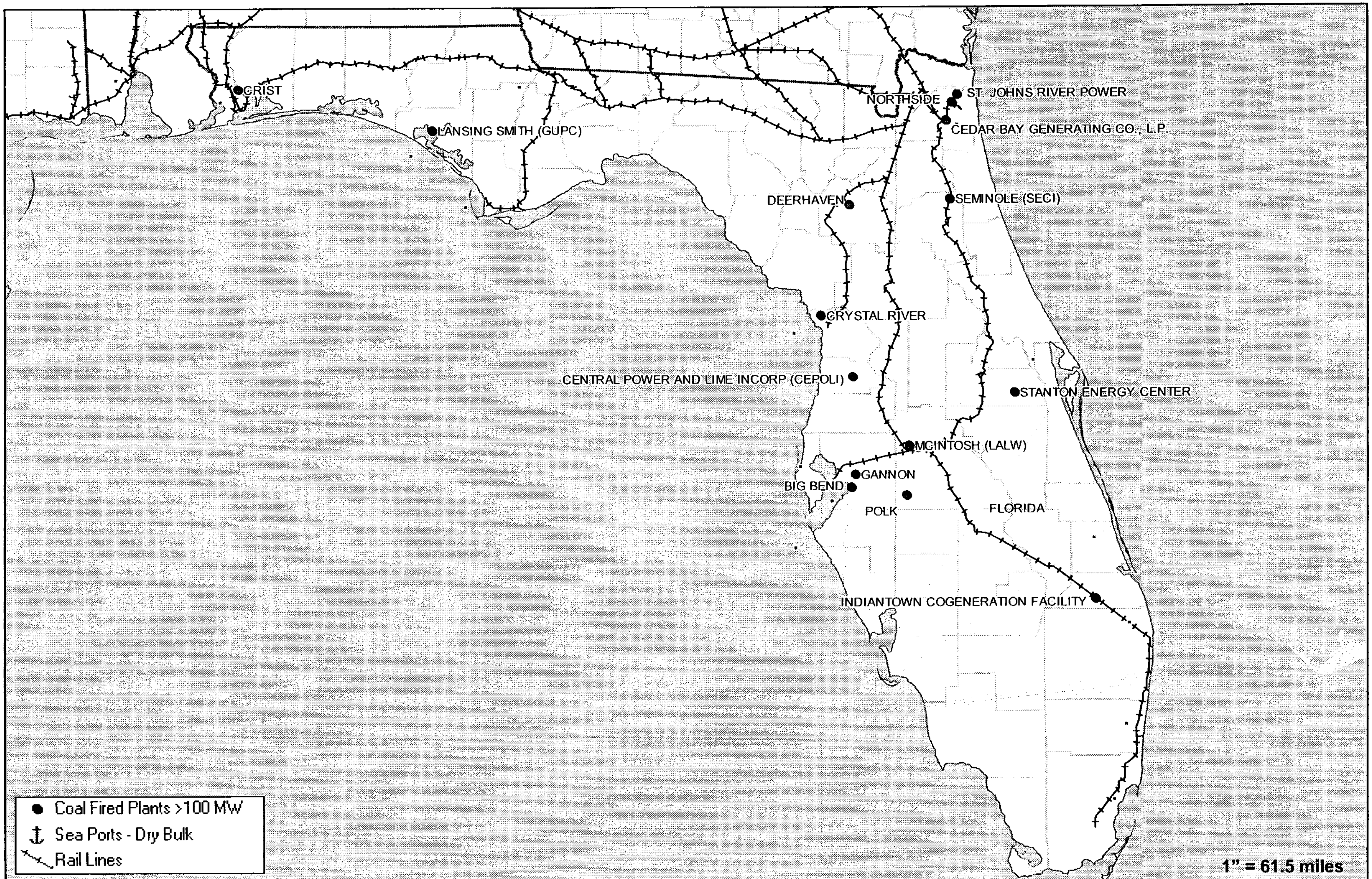



**Figure 6-1**

# Progress Energy

Coal Fired Power Plants

Burns & McDonnell SINCE 1898

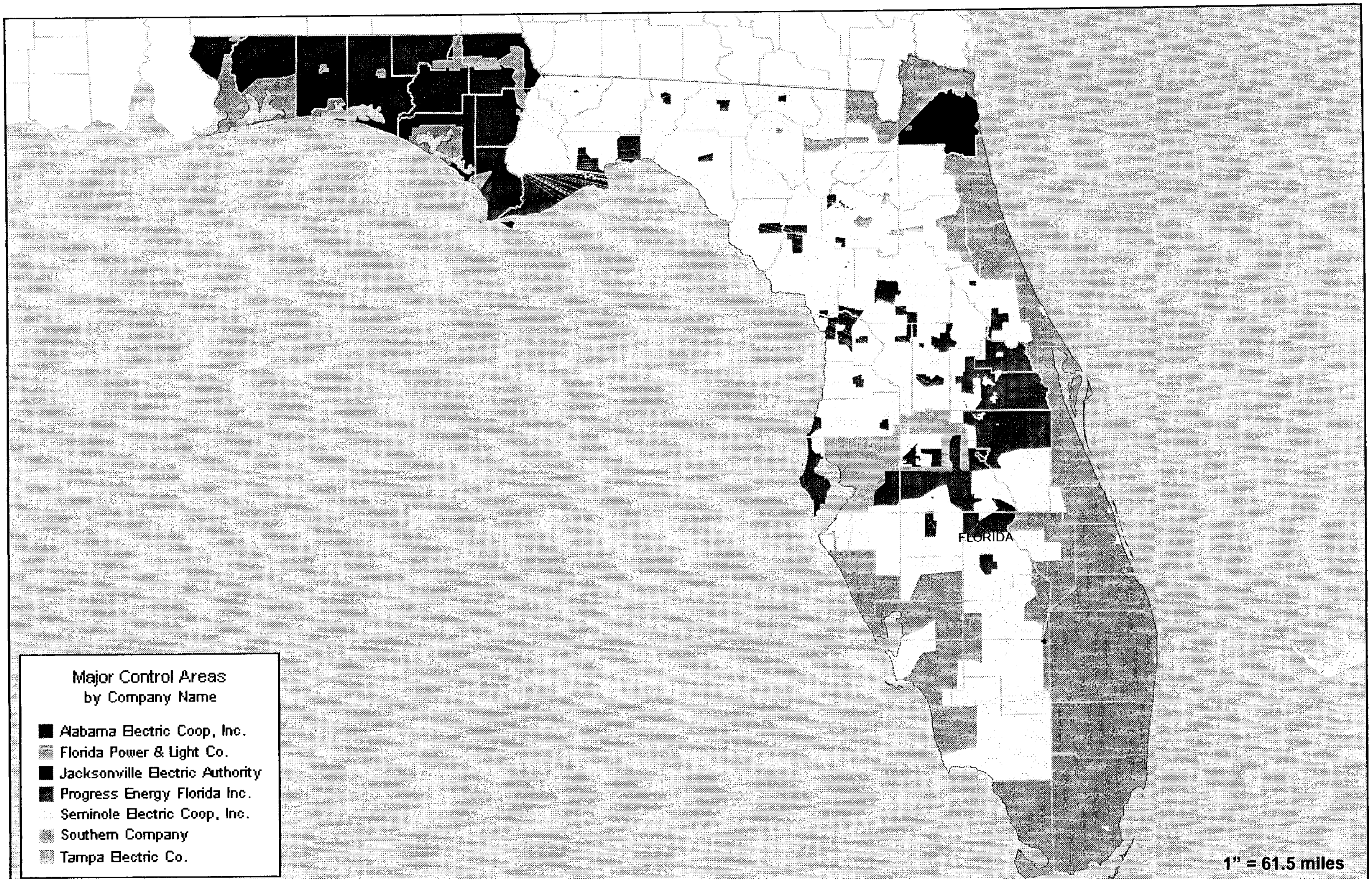



**Figure 6-2**

# Progress Energy

Major Control Areas

Burns & McDonnell
SINCE 1898

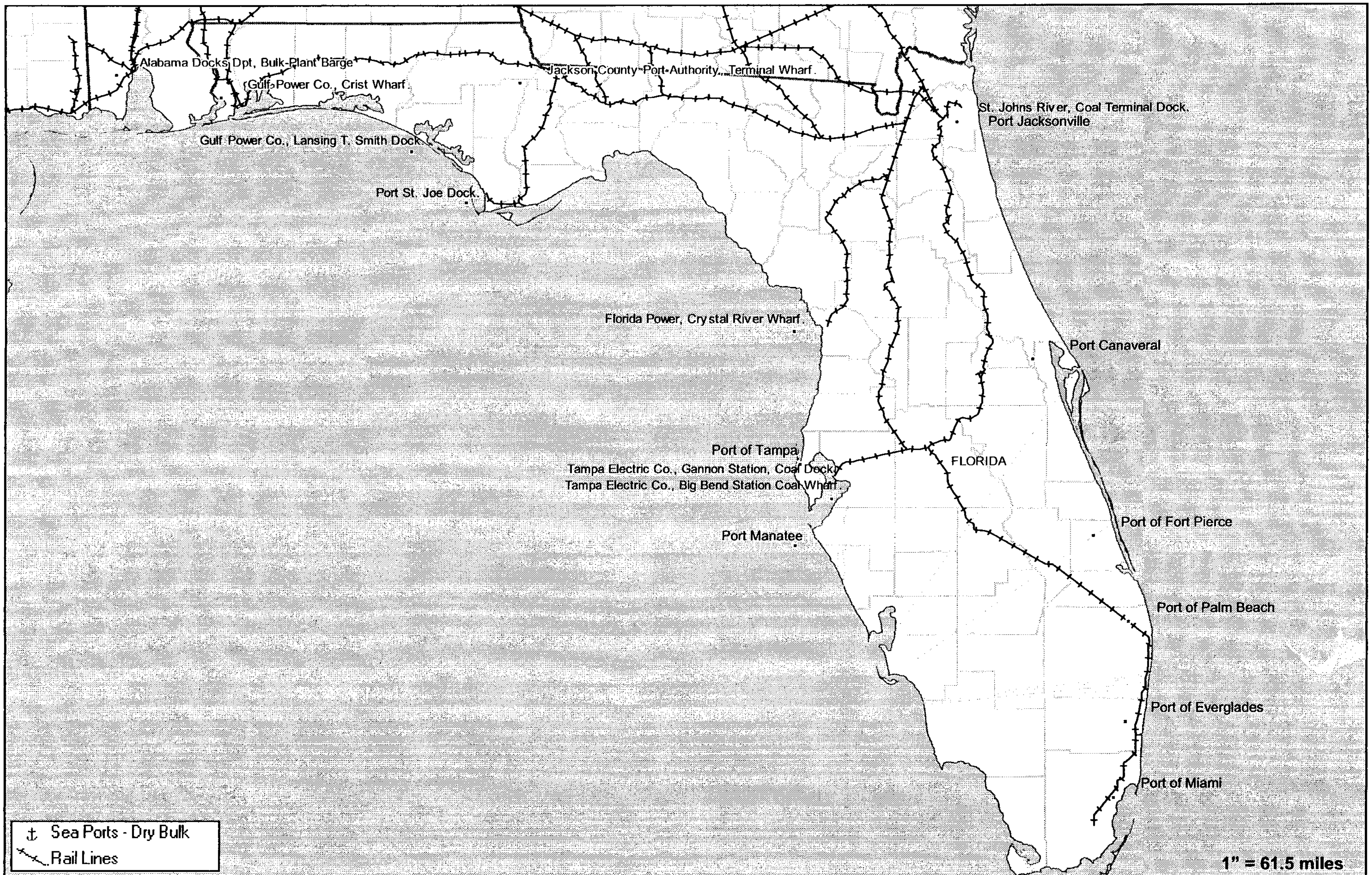



**Figure 6-3**

# Progress Energy

## Existing Fuel Delivery Infrastructure

Burns & McDonnell
SINCE 1898

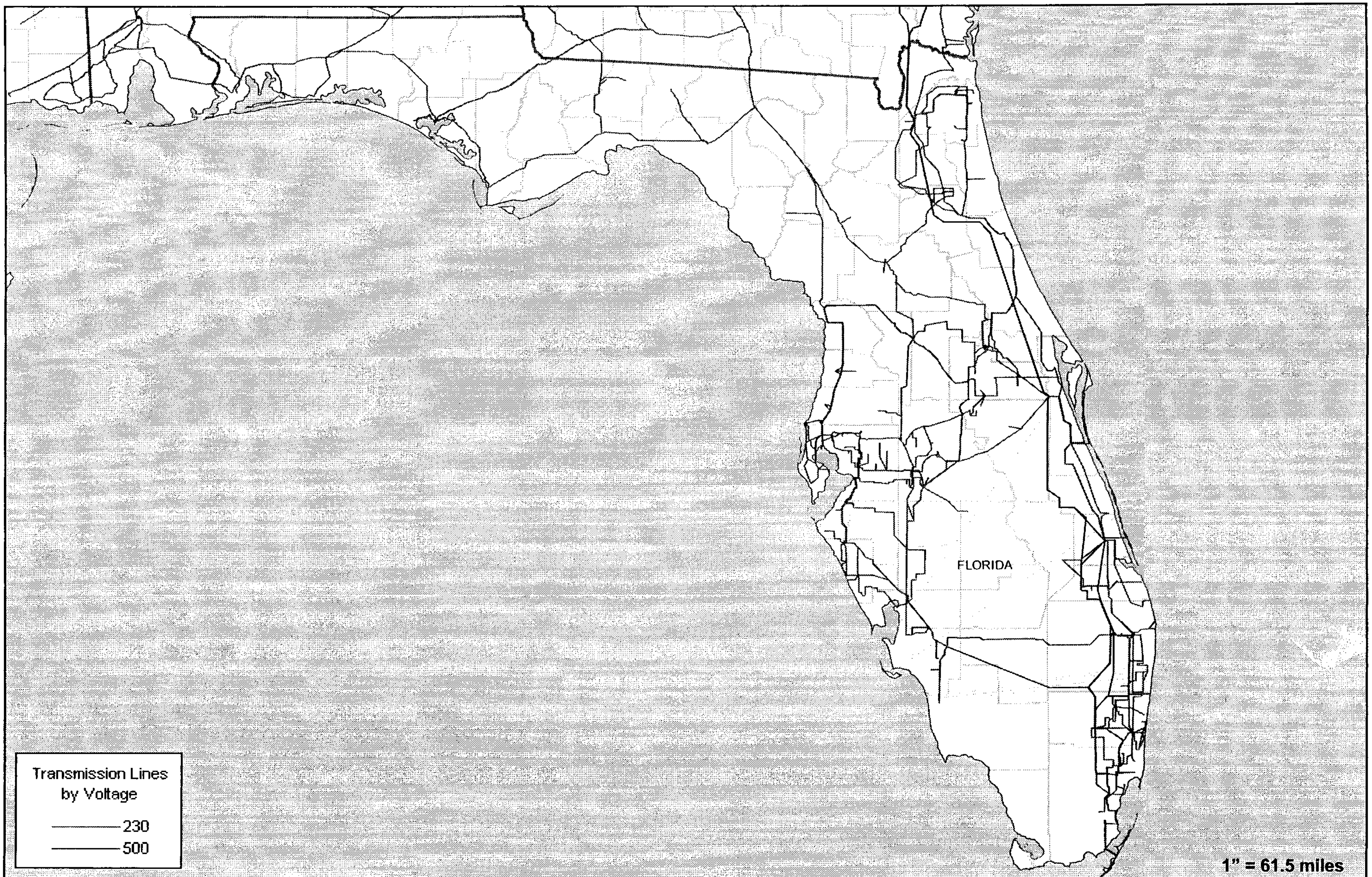



**Figure 6-4**

# Progress Energy

## Existing Transmission Infrastructure

Burns & McDonnell
SINCE 1898

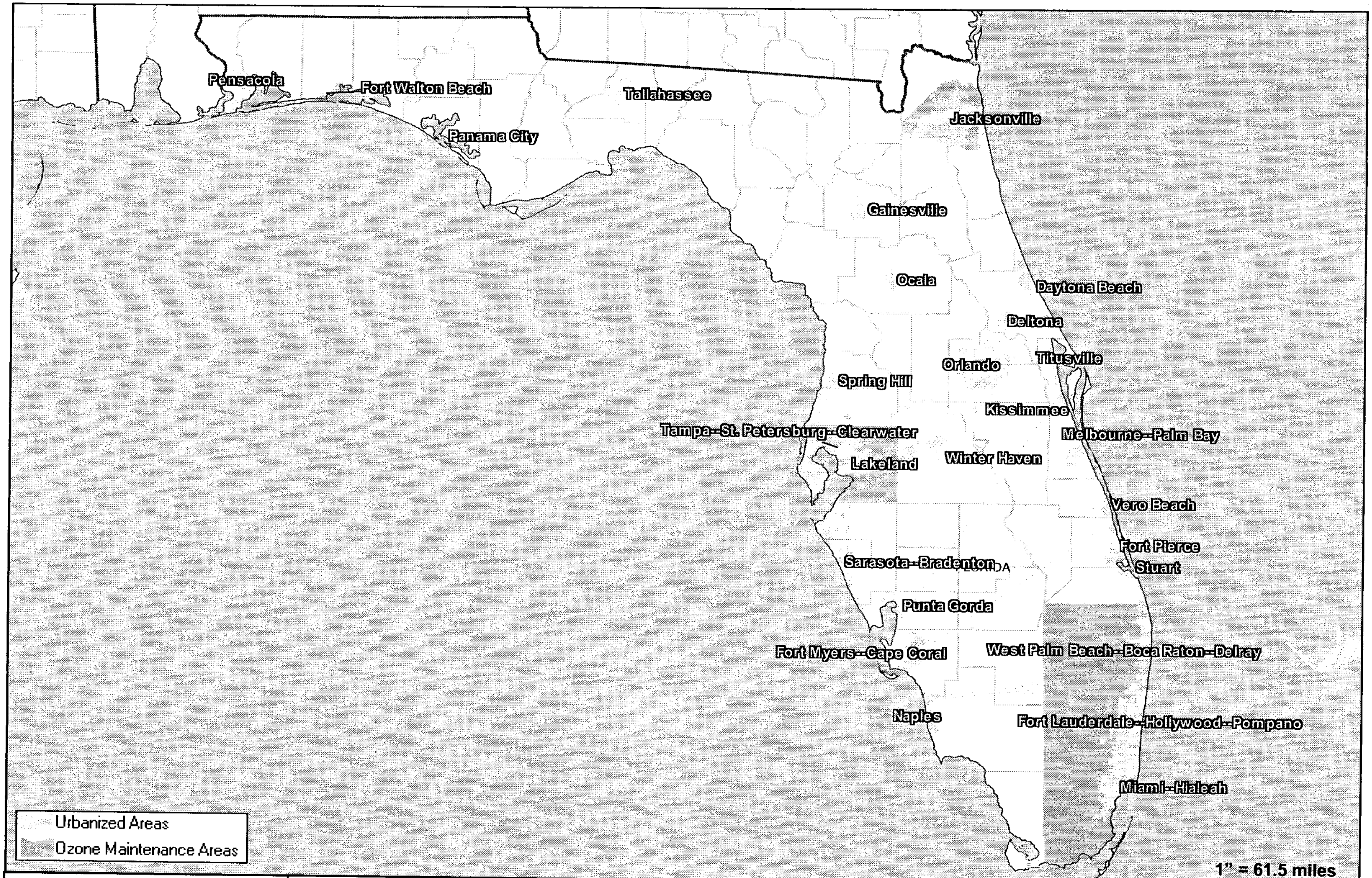



**Figure 6-5**

# Progress Energy

## Urban Areas and Non-Attainment Areas

Burns & McDonnell
SINCE 1898

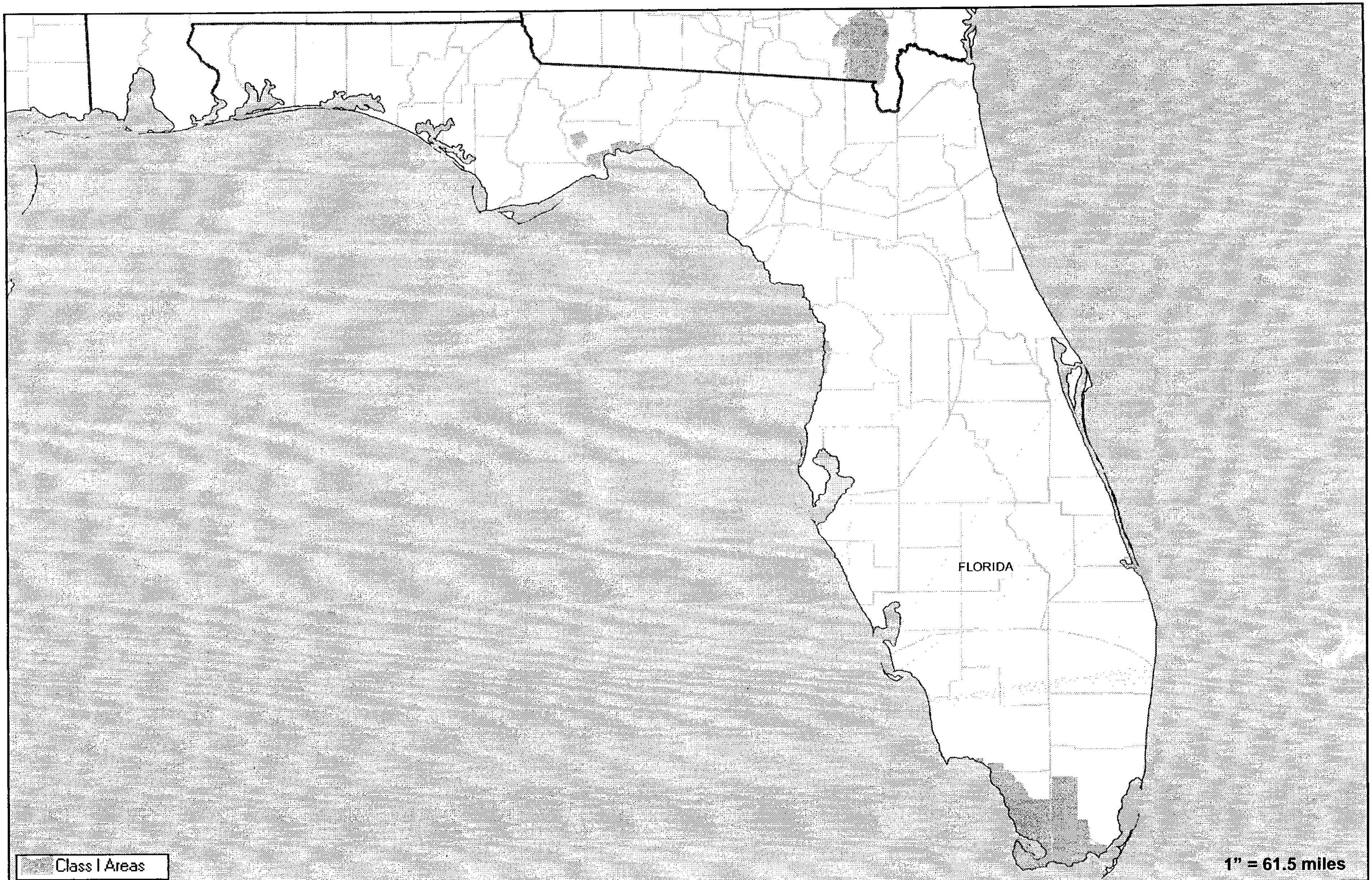



Figure 6-6

# Progress Energy

Class I Areas

Burns & McDonnell
SINCE 1898

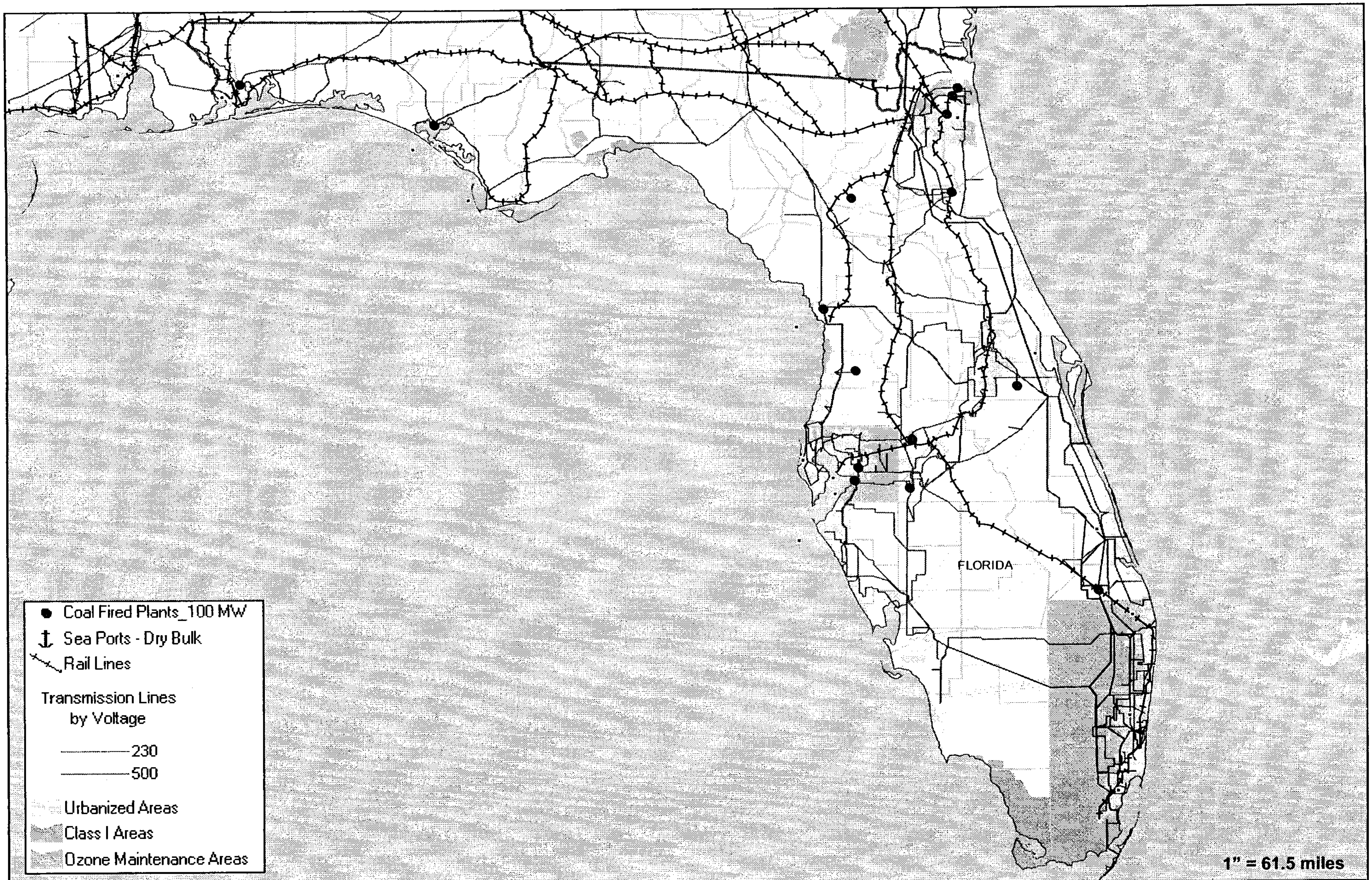



**Figure 6-7**

# Progress Energy

Florida State Overview Map

Burns & McDonnell SINCE 1898

# Section 7

# Schedule Issues

# SECTION 7
# SCHEDULE ISSUES

## 7.1 OBJECTIVE

B&McD prepared a schedule for the design and construction of a typical 500 MW solid fuel generation plant. This section also evaluates the integration of the regulatory, permitting and construction schedules with activities to consider for the next phase of development.

## 7.2 PROJECT CONSTRUCTION SCHEDULE

A preliminary schedule for the design and construction of the first 500 MW unit at a Greenfield site location is included in Appendix E. The total design/construction/startup for the first unit of the Project is estimated to require 54 months from full notice to proceed and procurement release to commercial operations. Construction time in the field is estimated to require 48 months. This schedule does not include site specific schedule impacts for the construction of a transmission line, which will have to be further evaluated when a specific siting study is performed. The execution method identified in the schedule is an engineering, procurement, construction (EPC) structure under which a single entity is responsible for design/construction/startup of the Project.

For a targeted commercial operation date of January 2011, the following milestones are identified:

| | |
|---|---|
| • Start Preliminary Engineering | February 2005 |
| • Start EPC Contract Package Development/Bid | February 2005 |
| • Submit CPCN and Air Permit Applications | June 2005 |
| • Award EPC Contract and Limited Notice to Proceed | March 2006 |
| • Full Notice to Proceed and Release Major Equipment | August 2006 |
| • Receive Final Permit Approval | February 2007 |
| • Start Construction | February 2007 |
| • Commercial Operation | January 2011 |

Site location, technology, unit size, and infrastructure development will all impact the schedule. It is possible to expedite the schedule presented, but the overall Project costs may increase.

## 7.3 PERMITTING SCHEDULE

Appendix C contained the preliminary environmental permit/clearance schedule. The application and approval of the Project's regulatory certificate and air permit will be the long lead permits to secure before construction of the Project can commence. The permit schedule reflects an approximate 30 month period from the time preliminary engineering for permit preparation is initiated until the site certification is issued to permit site construction. For a targeted commercial operation date of January 2011, the following permit milestones are identified:

- Start Preparation of CPCN and Air Permit Application July 2004
- Submit CPCN and Air Permit Applications June 2005
- Receive Final Permit Approval February 2007

An overlap in the permitting schedule and design/construction schedule exists. The EPC contractor will have to be selected and provided a limited notice to proceed in March 2006. A full notice to proceed and release of major equipment procurement (i.e., boiler island and turbine island) will need to occur in August 2006. Both of these events and the associated financial commitments will be made prior to receiving the final permit approvals in early 2007 in order to maintain a January 2011 schedule.

## 7.4 DEVELOPMENT SCHEDULE AND ACTION ITEMS

The other major development requirements to be completed prior to beginning preparation of the environmental permits and regulatory filings is to identify a candidate site(s), secure the site, and conduct a power supply RFP for baseload energy requirements pursuant to Rule 25-22.082 of the Florida Administrative Code. Rule 25-22.082 of the Florida Administrative Code requires investor-owned utilities to provide a description of the "next planned generating unit" on which the RFP is based. Progress is currently going through this process for the Hines Energy Complex Unit 4, located in Polk County, Florida.

### 7.4.1 Siting Schedule

A siting study to identify specific candidate site(s) locations should require approximately 4 to 6 months to complete. During the siting study, a conceptual engineering effort should be undertaken to refine the generic cost estimates presented in this study based on specific candidate site locations, potential fuel supply and delivery alternatives, and technology preferences. The conceptual engineering effort would also develop the RFP requirements needed to meet Rule 25-22.082 if a new solid fuel generation resource was the preferred alternative. Overall, the siting study and conceptual engineering effort, including management decisions to proceed with a solid fuel resource, will require 6 to 8 months. Progress should then proceed to secure a primary and possible secondary site before proceeding with the submission of any permits and/or regulatory filings. This process could take 2 to 4 months dependent upon specific site locations and land availability. An existing brownfield location would significantly reduce the site acquisition timeframe.

### 7.4.2 RFP Schedule

The current power supply solicitation schedule for the Hines IV unit outlines a 13-month process, comprising four phases: (1) Pre-Submission; (2) Evaluation Process; (3) Contract Negotiations; and (4) Regulatory Filings.

- Pre-Submission — September 10, 2003 – December 16, 2003
- Evaluation Process — December 16, 2003 – April 27, 2004
- Contract Negotiations — April 28, 2004 – July 27, 2004
- Regulatory Filings — July 27, 2004 – September 27, 2004

It is reasonable to assume the power supply evaluation and solicitation process for a proposed baseload energy resource would require 12 to 18 months also. If an RFP document was ready for issuance by the 3rd quarter of 2004, the earliest anticipated date for conclusion and submittal of the regulatory filings would be 3rd quarter of 2005.

### 7.4.3 Overall Schedule

For planning purposes, the key milestone dates working backward from a January 2011 commercial operation date for a new solid fuel generation resource would be the following:

- Commercial Operation — January 2011
- Start Construction — February 2007
- Receive Final CPCN/Air Permit Approval — February 2007
- Full Notice to Proceed and Release Major Equipment — August 2006
- Award EPC Contract and Limited Notice to Proceed — March 2006
- Submit CPCN and Air Permit Applications — June 2005
- Start EPC Contract Package Development/Bid — February 2005
- Start Preliminary Engineering — February 2005

- Issue RFP for Power Supply July 2004
- Initiate Siting Study January 2004

The schedule above indicates that a 2011 commercial operation date will likely require that Progress proceed with preliminary engineering, permitting, and EPC contract package development and bidding prior to completing the evaluation and negotiation of the power supply RFP results. In addition, this assumes that Progress will immediately undertake siting study and conceptual engineering efforts in 2004 to identify and evaluate candidate site locations, and confirm whether a new solid fuel generation resource is the preferred alternative for meeting energy requirements in the 2011-2030 planning period. Overall, the schedule is very aggressive to meet a targeted commercial operation date of January 2011. A more realistic planning timeframe that would allow full regulatory and management review would be to target a commercial operation date of January 2012 for a greenfield site. If a brownfield expansion site is available, a 2011 commercial operation date is more viable. While the construction schedule for a brownfield expansion would only be reduced by a few months, the development and permitting time frame can also be reduced by several months since an existing site is under control.

## 7.5 Action Item Recommendations

Burns & McDonnell recommends that Progress proceed immediately with a siting study to identify specific candidate site(s) locations and a conceptual engineering effort to refine the generic cost estimates presented in this study based on specific candidate site locations, potential fuel supply and delivery alternatives, technology preferences, and environmental constraints. The conceptual engineering effort would also develop the RFP requirements needed to meet Rule 25-22.082 if a new solid fuel generation resource was the preferred alternative meeting energy requirements in the 2011-2030 planning period. Overall, the siting study and conceptual engineering effort, including management decisions to proceed with a solid fuel resource, will require 6 to 8 months.

# Appendix A

**PROGRESS ENERGY SUMMARY TABLE**
**BASE CASE PROJECT OPTIONS**
**B&McD Project Number 35076**

| PROJECT TYPE | 500 MW PC Subcritical | 750 MW PC Subcritical | 1000 MW PC Subcritical | 500 MW PC Supercritical | 750 MW PC Supercritical | 1000 MW PC Supercritical | 500 MW CFB | 750 MW CFB | 1000 MW CFB | 500 MW IGCC |
|---|---|---|---|---|---|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | | | | | | | | | | |
| Number of Gas Turbines | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 2 |
| Number of Boilers/HRSGs | 1 | 1 | 2 | 1 | 1 | 2 | 2 | 3 | 4 | 2 |
| Number of Steam Turbines | 1 | 1 | 2 | 1 | 1 | 2 | 1 | 1 | 2 | 1 |
| Steam Conditions (Main Steam / Reheat) | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F |
| Steam Cycle Type | Subcritical | Subcritical | Subcritical | Supercritical | Supercritical | Supercritical | Subcritical | Subcritical | Subcritical | Subcritical |
| Fuel Design | 100% PRB | 100% PRB | 100% PRB | 100% PRB | 100% PRB | 100% PRB | 100% PRB | 100% PRB | 100% PRB | 100% PRB & 100% Pet Coke |
| Fuel Delivery | Rail | Rail | Rail | Rail | Rail | Rail | Rail | Rail | Rail | Rail |
| Heat Rejection | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower |
| NOx Control | SCR | SCR | SCR | SCR | SCR | SCR | SNCR | SNCR | SNCR | SCR |
| SO2 Control | Dry Scrubber | Dry Scrubber | Dry Scrubber | Dry Scrubber | Dry Scrubber | Dry Scrubber | Limestone Inj. w/ Polishing Scrubber | Limestone Inj. w/ Polishing Scrubber | Limestone Inj. w/ Polishing Scrubber | Sulfur Removal from Fuel |
| Particulate Control | Baghouse | Baghouse | Baghouse | Baghouse | Baghouse | Baghouse | Baghouse | Baghouse | Baghouse | Gaseous Fuel |
| Ash Disposal | Landfill On Site | Landfill On Site | Landfill On Site | Landfill On Site | Landfill On Site | Landfill On Site | Landfill On Site | Landfill On Site | Landfill On Site | N/A |
| Location | Inland - Florida | Inland - Florida | Inland - Florida | Inland - Florida | Inland - Florida | Inland - Florida | Inland - Florida | Inland - Florida | Inland - Florida | Inland - Florida |
| Greenfield/Brownfield Site | Greenfield | Greenfield | Greenfield | Greenfield | Greenfield | Greenfield | Greenfield | Greenfield | Greenfield | Greenfield |
| Wastewater Disposal | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream |
| Capital Cost, $/kW (All Inclusive) | 1,542 | 1,377 | 1,400 | 1,569 | 1,402 | 1,425 | 1,619 | 1,454 | 1,477 | 1,800 [1] |
| Capital Cost, $/kW (Typical EPC Cost) | 1,440 | 1,301 | 1,334 | 1,467 | 1,326 | 1,359 | 1,516 | 1,377 | 1,412 | 1,697 |

**ADJUSTMENTS TO BASE CASE OPTIONS**
**B&McD Project Number 35076**

| Capital Cost Adjustments | 500 MW PC Subcritical | 750 MW PC Subcritical | 1000 MW PC Subcritical | 500 MW PC Supercritical | 750 MW PC Supercritical | 1000 MW PC Supercritical | 500 MW CFB | 750 MW CFB | 1000 MW CFB | 500 MW IGCC |
|---|---|---|---|---|---|---|---|---|---|---|
| Brownfield Site (2) | (250) | (170) | (120) | (250) | (170) | (120) | (250) | (170) | (120) | (250) |
| Coastal Location (3) | 65 | 50 | 30 | 65 | 50 | 30 | 70 | 55 | 35 | 23 |
| Ship & Barge Unloading Facility (in lieu of rail) | 50 | 35 | 25 | 50 | 35 | 25 | 50 | 35 | 25 | 50 |
| Ship & Barge Unloading Facility (in addition to rail) | 85 | 60 | 45 | 85 | 60 | 45 | 85 | 60 | 45 | 85 |
| Dry Cooling | 53 | 53 | 53 | 52 | 52 | 52 | 53 | 53 | 53 | 22 |
| Wet Scrubber (No Flyash/Gypsum Sales) | 48 | 48 | 48 | 47 | 47 | 47 | N/A | N/A | N/A | N/A |
| Wet Scrubber (Flyash/Gypsum Sales) | 48 | 48 | 48 | 47 | 47 | 47 | N/A | N/A | N/A | N/A |
| Zero Discharge by use of Side Stream Softener, Hereo, & Crustallizer (Flyash/Gypsum Sales) (6) | 88 | 67 | 54 | 0 | 0 | 0 | See Note 6 | See Note 6 | See Note 6 | See Note 6 |
| 100% Imported Coal (In lieu of PRB) (7) | (32) | (32) | (32) | (32) | (32) | (32) | (57) | (57) | (57) | N/A (8) |
| 100% Bituminous Coal (In lieu of PRB) (9 & 10) | 43 | 43 | 43 | 43 | 43 | 43 | (54) | (54) | (54) | N/A (8) |
| 100% Pet Coke (In lieu of PRB) (10) | N/A | N/A | N/A | N/A | N/A | N/A | 25 | 25 | 25 | N/A (8) |

**PROGRESS ENERGY SUMMARY TABLE**
**BASE CASE PROJECT OPTIONS**
**B&McD Project Number 35076**

| PROJECT TYPE | 500 MW PC Subcritical | 750 MW PC Subcritical | 1000 MW PC Subcritical | 500 MW PC Supercritical | 750 MW PC Supercritical | 1000 MW PC Supercritical | 500 MW CFB | 750 MW CFB | 1000 MW CFB | 500 MW IGCC |
|---|---|---|---|---|---|---|---|---|---|---|
| **BASE PLANT DESCRIPTION** | | | | | | | | | | |
| Number of Gas Turbines | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 2 |
| Number of Boilers/HRSGs | 1 | 1 | 2 | 1 | 1 | 2 | 2 | 3 | 4 | 2 |
| Number of Steam Turbines | 1 | 1 | 2 | 1 | 1 | 2 | 1 | 1 | 2 | 1 |
| Steam Conditions (Main Steam / Reheat) | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F | 1050 F/1050 F |
| Steam Cycle Type | Subcritical | Subcritical | Subcritical | Supercritical | Supercritical | Supercritical | Subcritical | Subcritical | Subcritical | Subcritical |
| Fuel Design | 100% PRB | 100% PRB | 100% PRB | 100% PRB | 100% PRB | 100% PRB | 100% PRB | 100% PRB | 100% PRB | 100% PRB & 100% Pet Coke |
| Fuel Delivery | Rail | Rail | Rail | Rail | Rail | Rail | Rail | Rail | Rail | Rail |
| Heat Rejection | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower | Wet Cooling Tower |
| NOx Control | SCR | SCR | SCR | SCR | SCR | SCR | SNCR | SNCR | SNCR | SCR |
| SO2 Control | Dry Scrubber | Dry Scrubber | Dry Scrubber | Dry Scrubber | Dry Scrubber | Dry Scrubber | Limestone Inj. w/ Polishing Scrubber | Limestone Inj. w/ Polishing Scrubber | Limestone Inj. w/ Polishing Scrubber | Sulfur Removal from Fuel |
| Particulate Control | Baghouse | Baghouse | Baghouse | Baghouse | Baghouse | Baghouse | Baghouse | Baghouse | Baghouse | Gaseous Fuel |
| Ash Disposal | Landfill On Site | Landfill On Site | Landfill On Site | Landfill On Site | Landfill On Site | Landfill On Site | Landfill On Site | Landfill On Site | Landfill On Site | N/A |
| Location | Inland - Florida | Inland - Florida | Inland - Florida | Inland - Florida | Inland - Florida | Inland - Florida | Inland - Florida | Inland - Florida | Inland - Florida | Inland - Florida |
| Greenfield/Brownfield Site | Greenfield | Greenfield | Greenfield | Greenfield | Greenfield | Greenfield | Greenfield | Greenfield | Greenfield | Greenfield |
| Wastewater Disposal | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream | Water Discharge to Stream |
| Net Plant Output, kW | 500,000 | 750,000 | 1,000,000 | 500,000 | 750,000 | 1,000,000 | 500,000 | 750,000 | 1,000,000 | 500,000 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 9,100 | 9,377 | 9,090 | 8,845 | 9,115 | 8,835 | 9,518 | 9,914 | 9,502 | 8,900 |
| Heat Input, MMBtu/h (HHV) | 4,550 | 7,033 | 9,090 | 4,423 | 6,836 | 8,835 | 4,759 | 7,436 | 9,502 | 4,450 |
| Start-up Time, min | 65-120 | 65-120 | 65-120 | 90-120 | 90-120 | 90-120 | | | | |
| Minimum Load, % of MCR | 30% | 30% | 30% | 30% | 30% | 30% | 40% | 40% | 40% | |
| Ramp Rate, %/min | 2 - 3% | 2 - 3% | 2 - 3% | 4 - 5% | 4 - 5% | 4 - 5% | 4 - 5% | 4 - 5% | 4 - 5% | |
| Equivalent Forced Outage Factor, % | 6.7% | 6.7% | 6.7% | 6.7% | 6.7% | 6.7% | 5.3% | 5.3% | 5.3% | |
| Permanent Plant Staffing Requirement (# of people) | 110 | 115 | 130 | 110 | 115 | 130 | 125 | 135 | 145 | -- |
| Raw Water Consumption, GPM | 8,333 | 12,500 | 16,667 | 8,100 | 12,150 | 16,200 | 8,333 | 12,500 | 16,667 | 2,778 |
| Wastewater Discharge, GPM | 1,333 | 2,000 | 2,667 | 1,296 | 1,944 | 2,592 | 1,333 | 2,000 | 2,667 | 444 |
| Lime Consumption, TPY | 12,324 | 18,485 | 24,647 | 11,979 | 17,968 | 23,957 | N/A | N/A | N/A | N/A |
| Limestone Consumption, TPY | 0 | 0 | 0 | 0 | 0 | 0 | 80,825 | 121,238 | 161,650 | N/A |
| Flyash Production, TPY | 124,385 | 186,577 | 248,770 | 120,902 | 181,353 | 241,804 | 163,144 | 244,716 | 326,288 | N/A |
| Fixed O&M Cost, $/kW-Yr | 23.61 | 17.60 | 14.03 | 23.61 | 17.60 | 14.03 | 26.24 | 19.95 | 15.35 | 23.60 |
| Variable O&M Cost, $/MWh | 2.76 | 2.76 | 2.50 | 2.71 | 2.71 | 2.46 | 2.72 | 2.60 | 2.47 | 3.35 |

**ADJUSTMENTS TO BASE CASE OPTIONS**
**B&McD Project Number 35076**

| PROJECT TYPE | 500 MW PC Subcritical | 750 MW PC Subcritical | 1000 MW PC Subcritical | 500 MW PC Supercritical | 750 MW PC Supercritical | 1000 MW PC Supercritical | 500 MW CFB | 750 MW CFB | 1000 MW CFB | 500 MW IGCC |
|---|---|---|---|---|---|---|---|---|---|---|
| **ADJUSTMENTS FOR BROWNFIELD SITE** | | | | | | | | | | |
| Differential Permanent Plant Staff | (90) | (95) | (90) | (90) | (95) | (90) | (105) | (115) | (105) | -- |
| Differential Fixed O&M Cost, $/kW-Yr | (15.82) | (11.14) | (7.91) | (15.82) | (11.14) | (7.91) | (15.82) | (11.14) | (7.91) | (15.82) |
| **ADJUSTMENTS FOR COASTAL LOCATION** | | | | | | | | | | |
| Differential Net Plant Heat Rate, Btu/kWh (HHV) | 12 | 13 | 12 | 12 | 13 | 12 | 13 | 13 | 13 | 4 |
| Differential Raw Water Consumption, GPM | 27,800 | 41,701 | 55,601 | 27,800 | 41,701 | 55,601 | 27,800 | 41,701 | 55,601 | 9,267 |
| Differential Wastewater Discharge, GPM | 29,467 | 44,201 | 58,934 | 29,467 | 44,201 | 58,934 | 29,467 | 44,201 | 58,934 | 9,822 |
| Differential Variable O&M Cost, $/MWh | (0.46) | (0.46) | (0.46) | (0.46) | (0.46) | (0.46) | (0.46) | (0.46) | (0.46) | (0.15) |
| **DRY COOLING OPTION** (4) | | | | | | | | | | |
| Differential Net Plant Heat Rate, Btu/kWh (HHV) | 255 | 263 | 255 | 248 | 255 | 247 | 266 | 278 | 266 | 80 |
| Differential Raw Water Consumption, GPM | (7,666) | (11,500) | (15,334) | (7,452) | (11,178) | (14,904) | (7,666) | (11,500) | (15,334) | (2,555) |
| Differential Wastewater Discharge, GPM | (1,220) | (1,830) | (2,440) | (1,186) | (1,778) | (2,372) | (1,220) | (1,830) | (2,440) | (344) |
| Differential Variable O&M Cost, $/MWh | (0.51) | (0.51) | (0.51) | (0.49) | (0.49) | (0.49) | (0.51) | (0.51) | (0.51) | (0.17) |
| **WET SCRUBBER OPTION (No Flyash & Gypsum Sales)** | | | | | | | | | | |
| Differential Net Plant Heat Rate, Btu/kWh (HHV) | 120 | 124 | 120 | 117 | 120 | 116 | N/A | N/A | N/A | N/A |
| Differential Permanent Plant Staff | 15 | 15 | 24 | 15 | 15 | 24 | N/A | N/A | N/A | N/A |
| Differential Fixed O&M Cost, $/kW-Yr | 2.64 | 1.76 | 2.11 | 2.64 | 1.76 | 2.11 | N/A | N/A | N/A | N/A |
| Differential Raw Water Consumption, GPM | 167 | 250 | 333 | 162 | 243 | 324 | N/A | N/A | N/A | N/A |
| Differential Wastewater Discharge, GPM | 5 | 8 | 10 | 5 | 7 | 10 | N/A | N/A | N/A | N/A |
| Differential Lime Consumption, TPY | (12,324) | (18,485) | (24,647) | (11,979) | (17,968) | (23,957) | N/A | N/A | N/A | N/A |
| Differential Limestone Consumption, TPY | 31,603 | 47,404 | 63,205 | 30,718 | 46,077 | 61,436 | N/A | N/A | N/A | N/A |
| Differential Flyash Production, TPY | 19,279 | 28,919 | 38,558 | 18,739 | 28,109 | 37,479 | N/A | N/A | N/A | N/A |
| Differential Variable O&M Cost, $/MWh | (0.17) | (0.17) | (0.17) | (0.16) | (0.16) | (0.16) | N/A | N/A | N/A | N/A |

**ADJUSTMENTS TO BASE CASE OPTIONS**
**B&McD Project Number 35076**

| PROJECT TYPE | 500 MW PC Subcritical | 750 MW PC Subcritical | 1000 MW PC Subcritical | 500 MW PC Supercritical | 750 MW PC Supercritical | 1000 MW PC Supercritical | 500 MW CFB | 750 MW CFB | 1000 MW CFB | 500 MW IGCC |
|---|---|---|---|---|---|---|---|---|---|---|
| **WET SCRUBBER OPTION (Flyash & Gypsum Sales)** | | | | | | | | | | |
| Differential Net Plant Heat Rate, Btu/kWh (HHV) | 120 | 124 | 120 | 117 | 120 | 116 | N/A | N/A | N/A | N/A |
| Differential Permanent Plant Staff | 15 | 15 | 24 | 15 | 15 | 24 | N/A | N/A | N/A | N/A |
| Differential Fixed O&M Cost, $/kW-Yr[5] | 2.64 | 1.76 | 2.11 | 2.64 | 1.76 | 2.11 | N/A | N/A | N/A | N/A |
| Differential Raw Water Consumption, GPM | 193 | 290 | 387 | 188 | 282 | 376 | N/A | N/A | N/A | N/A |
| Differential Wastewater Discharge, GPM | 50 | 75 | 100 | 49 | 73 | 97 | N/A | N/A | N/A | N/A |
| Differential Lime Consumption, TPY | (12,324) | (18,485) | (24,647) | (11,979) | (17,968) | (23,957) | N/A | N/A | N/A | N/A |
| Differential Limestone Consumption, TPY | 31,603 | 47,404 | 63,205 | 30,718 | 46,077 | 61,436 | N/A | N/A | N/A | N/A |
| Differential Flyash Production, TPY | 19,279 | 28,919 | 38,558 | 18,739 | 28,109 | 37,479 | N/A | N/A | N/A | N/A |
| Differential Variable O&M Cost, $/MWh[5] | (0.30) | (0.30) | (0.30) | (0.29) | (0.29) | (0.29) | N/A | N/A | N/A | N/A |
| **ZERO DISCHARGE BY USE OF SIDE-STREAM SOFTENER, HERO, AND CRYSTALLIZER - FLYASH & GYPSUM SALES[6]** | | | | | | | | | | |
| Differential Net Plant Heat Rate, Btu/kWh (HHV) | 498 | 498 | 498 | 484 | 484 | 484 | See Note 6 | See Note 6 | See Note 6 | See Note 6 |
| Differential Permanent Plant Staff | 19 | 19 | 28 | 19 | 19 | 28 | See Note 6 | See Note 6 | See Note 6 | See Note 6 |
| Differential Fixed O&M Cost, $/kW-Yr | 3.34 | 2.23 | 2.46 | 3.34 | 2.23 | 2.46 | See Note 6 | See Note 6 | See Note 6 | See Note 6 |
| Differential Raw Water Consumption, GPM | (1,140) | (1,710) | (2,280) | (1,108) | (1,662) | (2,216) | See Note 6 | See Note 6 | See Note 6 | See Note 6 |
| Differential Wastewater Discharge, GPM | (1,333) | (2,000) | (2,667) | (1,296) | (1,944) | (2,592) | See Note 6 | See Note 6 | See Note 6 | See Note 6 |
| Differential Lime Consumption, TPY | (12,324) | (18,485) | (24,647) | (11,979) | (17,968) | (23,957) | See Note 6 | See Note 6 | See Note 6 | See Note 6 |
| Differential Limestone Consumption, TPY | 31,603 | 47,404 | 63,205 | 30,718 | 46,077 | 61,436 | See Note 6 | See Note 6 | See Note 6 | See Note 6 |
| Differential Flyash Production, TPY | 19,279 | 28,919 | 38,558 | 18,739 | 28,109 | 37,479 | See Note 6 | See Note 6 | See Note 6 | See Note 6 |
| Differential Variable O&M Cost, $/MWh | (0.16) | (0.16) | (0.16) | (0.16) | (0.16) | (0.16) | See Note 6 | See Note 6 | See Note 6 | See Note 6 |
| **100% IMPORTED COAL OPTION (In lieu of PRB)** | | | | | | | | | | |
| Differential Net Plant Heat Rate, Btu/kWh (HHV) | (207) | (213) | (207) | (201) | (207) | (201) | (324) | (338) | (324) | N/A[8] |
| Differential Lime Consumption, TPY | 7,019 | 10,528 | 14,037 | 6,822 | 10,233 | 13,644 | N/A | N/A | N/A | N/A[8] |
| Differential Limestone Consumption, TPY | N/A | N/A | N/A | N/A | N/A | N/A | 32,399 | 48,599 | 64,798 | N/A[8] |
| Differential Flyash Production, TPY | 37,825 | 56,737 | 75,650 | 36,766 | 55,149 | 73,532 | 93,978 | 140,967 | 187,956 | N/A[8] |
| Differential Variable O&M Cost, $/MWh | 0.23 | 0.23 | 0.23 | 0.23 | 0.23 | 0.23 | 0.00 | 0.00 | 0.00 | N/A[8] |
| **100% BITUMINOUS COAL OPTION (In lieu of PRB)[9]** | | | | | | | | | | |
| Differential Net Plant Heat Rate, Btu/kWh (HHV) | (160) | (167) | (163) | (155) | (162) | (159) | (407) | (424) | (407) | N/A[8] |
| Differential Permanent Plant Staff | 15 | 15 | 24 | 15 | 15 | 24 | 0 | 0 | 0 | N/A[8] |
| Differential Fixed O&M Cost, $/kW-Yr | 2.64 | 1.76 | 2.11 | 2.64 | 1.76 | 2.11 | 0 | 0 | 0 | N/A[8] |
| Differential Raw Water Consumption, GPM | 193 | 290 | 387 | 188 | 282 | 376 | 0 | 0 | 0 | N/A[8] |
| Differential Wastewater Discharge, GPM | 50 | 75 | 100 | 49 | 73 | 97 | 0 | 0 | 0 | N/A[8] |
| Differential Lime Consumption, TPY | (12,324) | (18,485) | (24,647) | (11,979) | (17,968) | (23,957) | N/A | N/A | N/A | N/A[8] |
| Differential Limestone Consumption, TPY | 156,744 | 235,116 | 313,488 | 152,355 | 228,532 | 304,710 | 293,726 | 440,589 | 587,452 | N/A[8] |
| Differential Flyash Production, TPY | 97,769 | 146,653 | 195,538 | 95,031 | 142,547 | 190,062 | 277,478 | 416,217 | 554,956 | N/A[8] |
| Differential Variable O&M Cost, $/MWh | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 2.19 | 2.19 | 2.19 | N/A[8] |
| **100% PET COKE (In lieu of PRB)** | | | | | | | | | | |
| Differential Net Plant Heat Rate, Btu/kWh (HHV) | N/A | N/A | N/A | N/A | N/A | N/A | (529) | (551) | (528) | N/A[8] |
| Differential Limestone Consumption, TPY | N/A | N/A | N/A | N/A | N/A | N/A | 584,950 | 877,425 | 1,169,900 | N/A[8] |
| Differential Flyash Production, TPY | N/A | N/A | N/A | N/A | N/A | N/A | 404,475 | 606,713 | 808,950 | N/A[8] |
| Differential Variable O&M Cost, $/MWh | N/A | N/A | N/A | N/A | N/A | N/A | 1.95 | 1.95 | 1.95 | N/A[8] |

**PROGRESS ENERGY SUMMARY TABLE NOTES**
**B&McD Project Number 35076**

Notes:
(1) Actual plants have ranged from $1215/kW to over $4500/kW. Solid Fuel IGCC operation is still very limited, therefore, actual plant heat rate values can vary from 8500 Btu/kWh to 9300+Btu/kWh.

(2) Adjustment for Brownfield assumes "typical" reuse of some of the facilities (roads, buildings, etc). Demolition of existing structures has not been included. The adjustment factor is very site specific and can vary very substantially depending on site specific constraints

(3) Adjustment for coastal location includes intake/outlet structures, piping, and pumps for use of seawater for cooling tower makeup, a titanium condenser, and a RFP Cooling Tower. The capital cost of ship/barge unloading facilities is not included and should be added separately (if desired). Because seawater can not be cycled up as much as groundwater, the makeup and blowdown rates are significantly higher.

(4) Dry cooling operating characteristics are very subject to ambient conditions. Data shown is a typical annual average heat rate impact. The heat rate difference will be greater at high dry bulb temperatures and less at low dry bulb temperatures. Plant output will vary also

(5) The O&M Costs included in this table include the increased blowdown of the wet scrubber for gypsum production. Because the market demand for flyash and gypsum is site specific, the O&M costs do not assume any cost benefit of selling the flyash and gypsum. However, the landfilling cost is eliminatec

(6) Zero discharge option assumes flyash and gypsum are intended to be produced for market. For gypsum sales, the scrubber water must be of higher quality, requiring more blowdown. This provides the largest wastewater stream, which is the worst case for sizing the crystallizer. In order to sell gypsum and flyash, a wet scrubber must be used. Therefore, the capital costs for the zero discharge option include a wet scrubber, side-stream softener, HERO, and Crystallizer. We are assuming this scrubber blowdown is routed directly to the crystallizer. Because a wet scrubber, flyash, and gypsum sales are PC specific, this analysis was not performed for the CFB and IGCC options. The eliminated landfilling costs are included in this analysis, however, there has been no cost benefit included for the sale of the gypsum and the flyash.

(7) Must add a ship unloading facility in addition to capital costs shown for imported coal option.

(8) There is not sufficient operating history of IGCC's to accurately determine the impacts of various fuels.

(9) Indications are that a PC boiler designed for Bituminous coal would require an ESP and Wet Scrubber to meet the emissions requirements. This option includes the capital and O&M costs for this equipment. No additional equipment is required for the CFB Option on Eastern Bituminous coal

(10) It is assumed the CFB Units operating on the Appalachian and Pet Coke fuels will require a polishing dry scrubber. The additional capital cost of this scrubber is include

**PROGRESS ENERGY SUMMARY TABLE NOTES**
**B&McD Project Number 35076**

The following assumptions govern this analysis:

General
- All estimates in this table are "screening level" and are not to be guaranteed.
- Capital costs include escalation to January 1, 2010 COD. O&M Costs are provided in $2003 USD.

- Capital costs include all anticipated direct costs, indirect costs, owners, costs, escalation, contingency, and profit. Financing Fees and Interest during Construction are not included in the Capital cost estimates.
- Output and heat rate estimates are at new & clean conditions. Degradation should be applied for the economic analysis.
- Plant capital cost ($/kW) is based on annual average output.
- The EPC cost estimates assume the projects are constructed on an open-shop basis.
- Typical buildings are included.

Tie-Ins
- Raw water supplyn infrastructure is included, based on installation of multiple wells on adjacent propert
- 1.5 Miles of Natural Gas pipeline is included with regulating station (for start-up)
- Estimate includes 500 kV ring bus switchyard and 1.5 miles of transmission lines
- A rail loop is provided for the site (unless indicated differently) to facilitate coal supply via unit train.
- Costs for rail cars for the unit train are NOT included.

Indirect Costs included in EPC estimate
- Air permitting, legal fees, site surveys, construction power & water, construction equipment, small tools & consumables, labor indirects, pre-operational testing, start-up, calibration, technical field assistance, performance testing, and 3 months of training.

Owner's Costs Included in EPC Estimate

- Project Development, Owner's operations personnel (during startup/commissioning), Owner's Engineer, Legal Council, Permitting & Licensing Fees, Start-up/testing fuel, 30 days of initial fuel inventory, startup power, test power sales, site security, builders risk insurance, workshop tools & test equipment, warehouse shelves, mobile equipment & vehicles, and furniture & laboratory equipment.

O&M Estimates are based on the following assumptions:
- O&M is estimated at the annual average ambient condition.
- Fuel costs are not included in the O&M analysis.
- 80% capacity factor.
- Demineralized and raw water production and treatment costs are included in the variable O&M analysis. Water treatment equipment is included in EPC capital cost.
- Estimated staff requirements and salaries are "typical" and are included in the fixed O&M analysis.

# Appendix B

## Generation Options BACT Comparison

| | PC | CFB | IGCC |
|---|---|---|---|
| Unit Configuration | 1 Boiler x 1 Steam Turbine | 2 Boiler x 1 Steam Turbine | 2 Combustion Turbine x 1 Steam Turbine |
| Unit Size (MW) | 500 | 2 x 250 | 2 x 250 |

### PRB Coal (8,400 Btu/lb; 0.34% Sulfur; 5.5% Ash; 30% Moisture)

| Criteria | Air Emissions (lb/MMBtu) / Control Technology | | Air Emissions (lb/MMBtu) / Control Technology | | Air Emissions (lb/MMBtu) / Control Technology | |
|---|---|---|---|---|---|---|
| $NO_X$ | 0.07 | LNB/OFA/SCR | 0.07 | SNCR | 0.07 | Steam/Diluent Injection |
| $SO_2$ | 0.10 | Spray Dryer Absorber | 0.12 (90-95% removal) | Limestone Injection into CFB | 0.04 | Gasification Process |
| CO | 0.15 | Good Combustion Control | 0.15 | Good Combustion Control | 0.10 | Good Combustion Control |
| $PM_{10}$ | 0.018 | Fabric Filter | 0.015 | Fabric Filter | 0.010 | Good Combustion Practices |
| VOC | 0.0036 | Good Combustion Control | 0.005 | Good Combustion Control | 0.005 | Good Combustion Control |

### Eastern Bituminous Coal (13,100 Btu/lb; 2.6% Sulfur; 9.1% Ash; 6% Moisture)

| Criteria | Air Emissions (lb/MMBtu) / Control Technology | | Air Emissions (lb/MMBtu) / Control Technology | | Air Emissions (lb/MMBtu) / Control Technology | |
|---|---|---|---|---|---|---|
| $NO_X$ | 0.07 | LNB/OFA/SCR | 0.07 | SNCR | 0.07 | Steam/Diluent Injection |
| $SO_2$ | 0.12 | Wet Scrubber | 0.2 (95-97% removal) | Limestone Injection/FGD | 0.2 | Gasification Process |
| CO | 0.15 | Good Combustion Control | 0.15 | Good Combustion Control | 0.10 | Good Combustion Control |
| $PM_{10}$ | 0.02 | ESP | 0.015 | Fabric Filter | 0.010 | Good Combustion Practices |
| VOC | 0.0036 | Good Combustion Control | 0.005 | Good Combustion Control | 0.005 | Good Combustion Control |

### Pet Coke (14,100 Btu/lb; 6.0% Sulfur; <1.0% Ash, ~7% Moisture Assumed)

| Criteria | Air Emissions (lb/MMBtu) / Control Technology | | Air Emissions (lb/MMBtu) / Control Technology | | Air Emissions (lb/MMBtu) / Control Technology | |
|---|---|---|---|---|---|---|
| $NO_X$ | N/A | N/A | 0.07 | SNCR | 0.07 | Steam/Diluent Injection |
| $SO_2$ | N/A | N/A | 0.25 (95-98% removal) | Limestone Injection/FGD | 0.43 | Gasification Process |
| CO | N/A | N/A | 0.15 | Good Combustion Control | 0.10 | Good Combustion Control |
| $PM_{10}$ | N/A | N/A | 0.015 | Fabric Filter | 0.010 | Good Combustion Practices |
| VOC | N/A | N/A | 0.005 | Good Combustion Control | 0.005 | Good Combustion Control |

### Imported Coal (11,000 Btu/lb; 0.65% Sulfur; 12% Ash; 11.7% Moisture)

| Criteria | Air Emissions (lb/MMBtu) / Control Technology | | Air Emissions (lb/MMBtu) / Control Technology | | Air Emissions (lb/MMBtu) / Control Technology | |
|---|---|---|---|---|---|---|
| $NO_X$ | 0.07 | LNB/OFA/SCR | 0.07 | SNCR | 0.07 | Steam/Diluent Injection |
| $SO_2$ | 0.10 | Spray Dryer Absorber | 0.12 (90-95% removal) | Limestone Injection into CFB | 0.06 | Gasification Process |
| CO | 0.15 | Good Combustion Control | 0.15 | Good Combustion Control | 0.10 | Good Combustion Control |
| $PM_{10}$ | 0.018 | Fabric Filter | 0.015 | Fabric Filter | 0.010 | Good Combustion Practices |
| VOC | 0.0036 | Good Combustion Control | 0.005 | Good Combustion Control | 0.005 | Good Combustion Control |

# Appendix C

# Environmental Permit Matrix

Solid-Fuel Power Facility in Florida

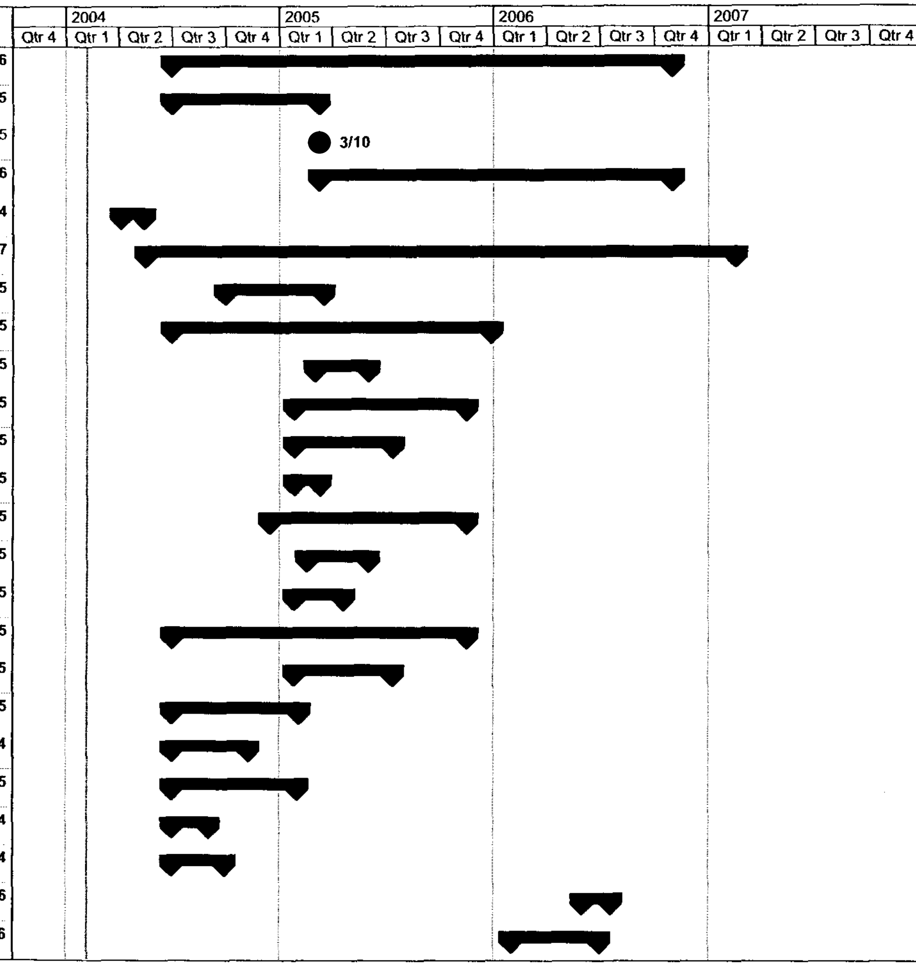
| Permit | Activity | Regulatory Basis | Responsible Agency | Contact Information | Permit Preparation Time | Permit Review Time | Cost to Prepare Permit and Track Agency Approval (site location may impact cost) | Construction/ Operation | Key Issues/Risks | Approval Requirements |
|---|---|---|---|---|---|---|---|---|---|---|
| **Site Certification** | Construction of a Steam Generating Power Facility greater than 75 MW | The Power Plant Siting Act Chapter 403.501-.518, F.S., Chapter 62-17 F.A.C. and Chapter 25-22 F.A.C. | The Florida Department of Environmental Protection, Siting Coordination Office is the lead review agency. The office of General Counsel acts as legal counsel and the Public Service Commission conducts the Need Determination. | Hamilton S. Oven, Florida Department of Environmental Protection, Siting Coordination Office Twin Towers Office Building Suite 649 2600 Blair Stone Road, MS 48, Tallahassee, FL 32399-2400 850-245-8002 | 180 days | 430 (or more) days | $283,100 | construction | The certificate application is not deemed complete until the following applications have been deemed complete: Prevention of Significant Deterioration, Title V A Operating Permit, and NPDES Industrial Discharge Permit, and Coastal Zone Consistency Statement, or any other permit required by a federally delegated program. Delegated agencies have specified time frames that which they must make a completeness determination. | Application preparation requires close coordination with federal, state, and local agencies having jurisdiction over project activities. Pre-application activities include a PSC review of a ten-year site plan, Notice of Intent, and Need Determination. The application must demonstrate a purpose and need for the project; provide a detailed project description, including associated facilities; describe the site environment; identify alternative sites and alternative technologies; and identify impacts to the environment and socioeconomics. A land use hearing administered by the Siting Office Administrative Law Judge is also required. |
| **Phase I Environmental Site Assessment** | Purchase of real estate | This activity is not required by a federal or state agency | Not Applicable | Not Available (Site Dependent) | 30 days | NA | $6,700 | construction | Purchase of contaminated property may cause new owner to be responsible for appropriate clean up and remediation in accordance with applicable rules | ASTM Standard E1527-00 is used for performing environmental site assessments for commercial real estate, should be implemented. This approach includes a site visual survey, an examination of files and records, interviews with current and former property owners, and a final report |
| **Permit to Construct, Operate, Modify, or Close a Solid Waste Management Facility** | Landfilling of ash waste | Chapter 62-701 F.A.C. | Respective District of the Florida Department of Environmental Protection | Solid Waste Supervisor, Respective District of the Florida Department of Environmental Protection | 540 days | 150 days | $621,600 | construction/ operation | Local opposition can result in schedule and cost impacts, or ultimately impact overall landfill site viability | Application will contain drawings and design report that indicate and document compliance with landfill layout and progression, protective liners, leachate collection and monitoring, construction quality assurance, and closure requirements. An operating report that establishes environmentally protective operating procedures to be followed at the landfill also is included. Hydrogeological and geotechnical investigations (including drilling) will be conducted, and investigation results will be evaluated and documented to support the landfill design and proposed groundwater monitoring plan. Documentation demonstrating compliance with other applicable siting criteria, including wetlands, surface water, and air must also be provided. Seventy-five percent of the estimated costs are associated with the required engineering needed to design the landfill, the remainder is associated with permitting activities. |
| **Local Zoning Conditional Use Permit** | Construction of industrial facilities in areas not zoned for industrial use (may be a distinction between light industry and heavy industry) | Applicable Local Ordinance | Applicable Local Municipality | Not Available (Site Dependent) | 30 days | 30 to 90 days | $17,500 | construction | Potential operating restriction due to off-site impacts. Approval influenced by local politics and public perspective. | If the property for the site is zoned anything other than industrial, a request for a change in zoning determination must be made. These requests typically require a public notice and sometimes a public hearing. Heavy industrial facilities may require a Conditional Use Permit even if the property is zoned for industrial use. A request for zoning change and/or a Conditional Use Permit typically requires a project description, cost of the project, potential impacts such as noise, traffic, and employment. |
| **Prevention of Significant Deterioration/New Source Review** | Construction of a new electric utility steam generating unit of greater than 250 million BTU (MMBtu) per hour heat input and has the potential to emit more than 100 tons per year of a criteria pollutant. | Prevention of Significant Deterioration/ New Source Review (PSD/NSR) 40 CFR Part 52, Chapter 62-212 F.A.C. | Florida Department of Environmental Protection, Tallahassee Air Division | Al Linero, Division of Air Resource Management 2600 Blair Stone Road, MS 5500 Tallahassee, FL 32399-2400 850-921-9523 | 120-180 days | 180-210 days | $122,100 | construction | Class I Areas include the Bradwell Bay, Okefenokee Swamp, Everglades, St. Marks, and Chassahowitzka. One year of preconstruction ambient air monitoring may be required if no representative monitors are located near the proposed site. Obtaining a PSD permit for an existing site (especially if existing sources emission sources are eliminated) will be permitted quicker than a greenfield site. Florida is in attainment with air quality standards. | Preparation of a permit application to construct a major emission source. Requires a pre-application, preparation and approval of a dispersion modeling protocol (CALPUFF), air dispersion modeling analysis (visibility, vegetation, NAAQS, PSD increment) and Best Available Control Technology (BACT) analysis |
| **Title IV - Acid Rain Permit** | Federal permit to monitor emissions from power plant | Title IV of the Clean Air Act 40 CFR Part 72-78, Chapter 62-214 F.A.C. | Environmental Protection Agency - Region IV | Air, Pesticides & Toxics Management Division 61 Forsyth Street Atlanta, GA 30303 Air Permits Section, Gregg Worley, Chief 404/562-9141 | 5 days | 30-60 days | $2,200 | construction | Allowances are available, there is no cap and or a trade system in place in Florida. | Requires preparation of and submittal of Form EIA – 860B to receive the ORIS Code and then preparation and submittal of the Phase II Acid Rain Application and Certificate of Representation to obtain the Title IV Acid Rain Permit Application. |
| **Title V - Operating Permit** | Federal permit to operate the plant, renewable every 5 years, and incorporate all permits - State requirement | Title V of the Clean Air Act 40 CFR Part 70, Chapter 62-213 F.A.C. | Florida Department of Environmental Protection, Tallahassee Air Division | Scot Shelpak, Division of Air Resource Management 2600 Blair Stone Road, MS 5500 Tallahassee, FL 32399-2400 850-921-9532 | 30 days | ----- | $11,100 | operation | The PSD permit application will be submitted and at the same time a request to review the same application as an operating permit application will be requested. The State will issue the PSD permit along with a pre-determination approval of an operating permit for the purpose of completing the siting application. | Florida Department of Environmental Protection will accept and review the PSD permit application as an operating permit application. This will be formally requested at the time the PSD permit application is submitted to the agency. |
| **Consumptive Use Permit or Water Use Permit** | Ground or Surface Water Withdrawal/Use | Chapter 40 F.A.C. | Respective Florida Water Management District | Respective Florida Water Management District | 30 days | 90 days | $6,700 | construction | The water management districts are developing minimum low flows for surface waters that may impact withdrawal approvals | Application must demonstrate the water use is reasonable and beneficial, will not interfere with other users, is consistent with the public interest, and will not harm the environment |
| **National Pollutant Discharge Elimination System: Generic Permit for Storm Water Discharges Associated with Industrial Activities** | Discharge of storm water from industrial facilities | Section 402 Clean Water Act, Chapter 62-621 F.A.C. | NPDES Stormwater Section, Florida Department of Environmental Protection | 2600 Blair Stone Road, MS #2500 Tallahassee, FL 32399-2400 850-245-7522 | 30 days | 2 days | $10,200 | operation | In addition to the NPDES general permit, the applicant may also be required obtain a Stormwater Discharge Permit as per 62-25 F.A.C. Dependent on location, additional notification to delegated water management districts and/or local municipalities may also be required. | A Notice of Intent must be submitted at least 2 days prior to commencement of industrial activity. The generic permit requires that a Storm Water Pollution Prevention Plan be developed and maintained on site. Development plan requires identification of Best Management Practices to minimize contamination of storm water runoff. Engineering details such as containment, coverage, and drainage patterns will be required. |
| **National Pollutant Discharge Elimination System Industrial Wastewater Permit** | Discharge of process wastewater to surface water or ground water | Section 316 and 402 Clean Water Act, Chapter 62-522 F.A.C. and Chapter 62-620 F.A.C. respectively | Industrial Wastewater Section, Florida Department of Environmental Protection | Vince Seibold, Industrial Wastewater Section 2600 Blair Stone Road, MS #2500 Tallahassee, FL 32399-2400 850-245-8589 | 60 days | 180 days | $16,100 | operation | Thermal characterization of the effluent will be reviewed to ensure it does not alter cold coastal waters so as to create manatee critical habitat solely dependent on an industrial discharge. | Application requirements include identification of all wastewater, including stormwater, raw water quality, estimated effluent quality, identification of chemical additives, description of treatment facilities, and a water balance showing daily maximum and average flows. |
| **Hydrostatic Discharge Authorization** | Discharge of hydrostatic test waters from new facilities | Section 316 and 402 Clean Water Act, Chapter 62-522 F.A.C. and Chapter 62-620 F.A.C. respectively | Respective District of the Florida Department of Environmental Protection | Respective District of the Florida Department of Environmental Protection | 15 days | 45-60 days | $3,100 | construction | If the test waters cannot percolate to avoid discharge to surface waters or if the discharge presents a water quality concern regarding toxic pollutants (usually a result of chemical additives), an Industrial Permit may be required which can take up to 180 days. | A letter requesting authorization and permit exemption should include the equipment being tested, location of discharges, demonstration of percolation, volume of discharge, estimated quality of discharge (based on raw water data), and chemical additives. Measures to prevent erosion and sedimentation must also be presented. |
| **Storm Water Discharge Permit** | Construction of storm water management facilities and storm water discharges to wetlands (see potential exemption in "key issues" text) | Chapter 62-25 F.A.C. | Respective District of the Florida Department of Environmental Protection or delegated Water Management Districts | Respective District of the Florida Department of Environmental Protection or delegated Water Management Districts | 30 days | 30 days | $8,000 | construction | The project may be exempt from this permit if certain parameters are met or may be authorized under an Environmental Resource Permit, thus preempting the requirement to obtain a separate permit under 62-25 F.A.C. | Application must demonstrate stormwater management facilities (detention ponds, swales, etc.) are designed in accordance with Chapter 62-25.025. |
| **National Pollutant Discharge Elimination System: Phase II Generic Permit for Storm Water Discharges Associated with Construction Activities** | Discharge of storm water from construction sites | Section 402 Clean Water Act, Chapter 62-621 F.A.C. | NPDES Stormwater Section Florida Department of Environmental Protection | 2600 Blair Stone Road, MS #2500 Tallahassee, FL 32399-2400 850-245-7522 | 30 days | 2 to 30 days | $8,000 | construction | In addition to the NPDES general permit, the applicant may also be required obtain a Stormwater Discharge Permit as per 62-25 F.A.C. Dependent on location, additional notification to delegated water management districts and/or local municipalities may also be required | A Notice of Intent must be submitted to the FDEP identifying the owner/operator, receiving stream(s), and identification of Best Management Practices (BMPs). BMPs are identified in a Storm Water Pollution Prevention Plan that must be retained on site and updated as BMPs are amended |

# Environmental Permit Matrix

Solid-Fuel Power Facility in Florida

| Permit | Activity | Regulatory Basis | Responsible Agency | Contact Information | Permit Preparation Time | Permit Review Time | Cost to Prepare Permit and Track Agency Approval (site location may impact cost) | Construction/ Operation | Key Issues/Risks | Approval Requirements |
|---|---|---|---|---|---|---|---|---|---|---|
| **Individual Permit and Water Quality Certification** | Dredge and/or fill of wetlands and/or navigable waters and utility stream crossings | Section 404 and 401 Clean Water Act, Section 10 Rivers and Harbors Act | U.S. Army Corps of Engineers , Jacksonville District | 701 San Marco Boulevard Jacksonville, FL 32207 904-232-1666 | | | | | An acceptable mitigation plan to compensate for impacts to wetlands and other waters of the United States must be provided | **This permit will be reviewed and issued along with the Environmental Resource Permit implemented by Florida.** A joint application will be prepared and submitted to the US Army Corps of Engineers and the respective district of the FDEP. The joint permit application includes site layout drawings with contours and wetland boundaries, impact analysis, alternatives analysis, detailed wetland delineation and report, and mitigation plan. The permit will undergo public notice. |
| **Environmental Resource Permit** | The Environmental Resource Permitting Program addresses dredging, filling, and construction in wetlands and other surface water, as well as stormwater and surface water management systems in uplands. | Chapter 62-312, 330, 345 F.A.C. | Respective District of the Florida Department of Environmental Protection | Respective District of the Florida Department of Environmental Protection | 180 days | 180 days | $153,200 | construction | State agency takes the lead and coordinates with the US Army Corps of Engineers. | In addition to the requirements set forth by the 404 Individual Permit, the joint application will also present stormwater analyses and drawings showing construction and post construction storm water management. This component will satisfy the requirements of Chapter 62-25 F.A.C., thus preempting the requirement for a Storm Water Discharge Permit. The NPDES permit for stormwater discharges will also be required. |
| **Sovereign Submerged Lands Use Agreement** | Easement or title of state-owned lands, usually encountered for major stream crossings of utility lines | Chapter 18-21 F A C | Respective District of the Florida Department of Environmental Protection, Submerged Lands and Environmental Resource Program or delegated Water Management District | Respective District of the Florida Department of Environmental Protection, Submerged Lands and Environmental Resource Program or delegated Water Management District | | | | | Title search can only be accomplished by the FDEP and can be a timely process. Survey will identify the submerged lands boundary. | **Approval for submerged land use agreements will be processed in conjunction with the Environmental Resource Permit.** Application requirements are the same as for the Environmental Resource Permit. |
| **Coastal Zone Consistency Review** | Federally licensed or permitted actions, construction projects within the seasonal high-water line and 1,500 feet landward in one of the 35 coastal counties | Coastal Zone Management Act, Chapter 380, Part II F.S | Florida Department of Environmental Protection, Coastal Management Program | Florida Department of Environmental Protection, Coastal Management Program 2600 Blair Stone Road Tallahassee, FL 32399-2400 850-245-2161 | 30 days | 90 days | $7,100 | construction | Approval of federal permits or license may be impacted if project activities are deemed inconsistent with 23 Florida Statutes that may regulate the project | Applicable federal permit or license applications will be reviewed by the Coastal Zone Program for consistency with the Coastal Zone Policies The Individual 404 Permit and 401 Water Quality Certification will require a coastal consistency review. |
| **Threatened & Endangered Species Clearance and Gopher Tortoise Incidental Take Permit** | Land disturbance and industrial activity | Section 7 Threatened and Endangered Species Act, Chapter 39 F A C | U S. Fish and Wildlife Service and Florida Fish and Wildlife Conservation Commission | USFWS-Chief, Division of Endangered Species U S. Fish and Wildlife Service 1875 Century Blvd., Suite 200 Atlanta, GA 30345 FWCC-Bureau of Wildlife Diversity Conservation 620 South Meridian Street, MS WLD-BLX Tallahassee, FL 32399-1600 (850) 921-5990 | 15 to 90 days | 45 to 90 days | $46,600 | construction | A key assumption with this scope is that, at a minimum, Gopher Tortoises will inhabit a portion of the selected site. Other state and federally protected species may also be present on the site and require additional surveys and mitigation. This effort does not include any mitigation related efforts for impacted T&E species. | Review and collection of available mapping, agency correspondence, and field investigation An Incidental Take permit will be required when gopher tortoise and the Indigo snake are encountered. A mitigation condition of the Gopher Tortoise Incidental Take Permit is that adequate compensatory occupied tortoise habitat is preserved and managed in perpetuity. |
| **Tree Removal Permit** | Tree clearing and/or trimming | Applicable Local Ordinance | Applicable Local Municipality | Not Available (Site Dependent) | 45 days | varies | $9,200 | construction | Mitigation ratio for tree replacement varies depending on quality of trees removed. | Applications generally require identification of tree species and size that will be removed. Mitigation of tree removal by placement of additional trees within the project property or other acceptable location must be presented. |
| **Phase I Cultural Resource Survey** | Land disturbance | Section 106 National Historic Preservation Act, Chapter 1A F.A C | Florida Division of Historical Resources | Laura Krammerer, Bureau of Historic Preservation 500 S. Bronough Street Tallahassee, FL 32399-0250 850-245-6333 | 90 days | 45 to 60 days | $44,400 | construction | Cultural resource sites may require mitigation (removal of artifacts) or avoidance of site locations. Mitigation will increase costs and lengthen schedule. | Identification of lead Federal agency, consultation with affected Tribes, review of available mapping, background research, agency consultation and survey permit, acquire land access, field investigations, artifact analysis, archaeological report, agency correspondence, labeling of artifacts, and curation |
| **Noise Abatement** | Industrial activity | Applicable Local Ordinance | Applicable Local Municipality | Not Available (Site Dependent) | 45 days | varies | $18,700 | construction | Distance to sensitive noise receptors may require additional noise abatement equipment be designed and installed. | An ambient noise assessment (monitoring) will be conducted at the project location to estimate pre-construction noise levels. The will include noise projections based on the proposed equipment The report will also include recommendations for noise abatement if warranted. |
| **Obstruction to Air Navigation** | Erection of structures over 200 feet or if structures are within the 100.1 elevation ratio | 14 CFR Part 77 | Federal Aviation Administration | Southern Regional Office Air Traffic Administration ASO-520 1701 Columbia Avenue College Park, GA 30337 404-305-5685 | 5 days | 45 to 60 days | $1,900 | construction | Potential to encroach on landstrip flight path and/or interfering with airport communication technology. Plume modeling may be required | The application must identify the location and heights of subject structures and proposed markings in accordance with FAA Advisory Circular 70/7460-1K Obstruction Markings and Lighting |
| **Storage Tank Registration** | Underground storage tanks 110 gallons or greater, above ground storage tanks 550 gallons or greater | Chapter 62-761 F A C | Florida Department of Environmental Protection Waste Management Division | Carol Camely, Bureau of Petroleum Storage 2600 Blair Stone Road Tallahassee, FL 32399-2400 850-245-8839 | 5 days | 30 days | $5,600 | operation | Typically, registration is a notification and fee payment type process requiring minimal time | Registration requires location, content, capacity, materials of construction , and monitoring methods be presented. |
| **Spill Prevention Control and Countermeasure Plan** | Storage of 1,320 gallons or more of petroleum products | 40 CFR Part 112 | U S Environmental Protection Agency | U.S. EPA, Region 4 Sam Nunn Atlanta Federal Center 61 Forsyth Street, SW Atlanta, GA 30303 404-562-9900 800-241-1754 | 30 days | 60 to 90 days in place before delivery of oil to site | $9,400 | operation | Development of a SPCC for green field facility requires coordination during the design process in order to insure that the plan is in place by the time oil is received on site. Secondary containment for fuel unloading areas and transformers can be problematic. | Identification of prevention measures and management of petroleum spills. The SPCC must be in place prior to filling of the storage tanks Site visit necessary after construction complete. Must be certified by registered engineer (Florida). NOTE: if site stores more than 1million gallons of fuel, a Facility Response Plan will also be required. The FRP is submitted to the EPA for approval |

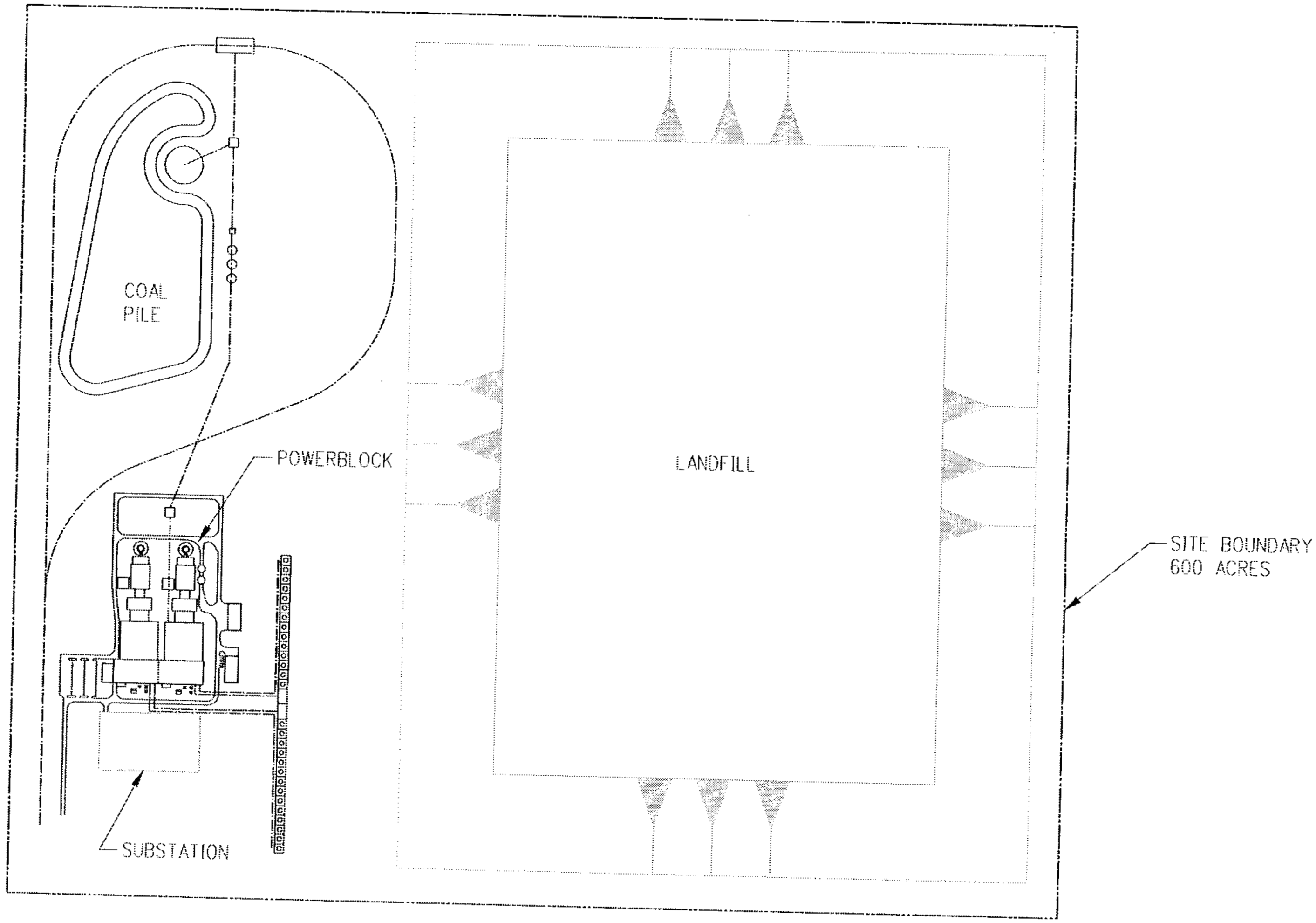
| ID | | Task Name | Duration | Start | Finish |
|---|---|---|---|---|---|
| 1 | | Site Certification/Agency Coordination | 610 days | Thu 7/1/04 | Wed 11/1/06 |
| 2 | | Prepare Application | 180 days | Thu 7/1/04 | Wed 3/9/05 |
| 4 | | Submit Application | 1 day | Thu 3/10/05 | Thu 3/10/05 |
| 5 | | Agency Review | 430 days | Thu 3/10/05 | Wed 11/1/06 |
| 7 | | Phase I Environmental Site Assessment | 30 days | Mon 4/5/04 | Fri 5/14/04 |
| 10 | | Permit for a Solid Waste Management Facility | 720 days | Mon 5/17/04 | Fri 2/16/07 |
| 13 | | Local Zoning Conditional Use Permit | 120 days | Fri 10/1/04 | Thu 3/17/05 |
| 16 | | Prevention of Significant Deterioration/New Source Review | 390 days | Thu 7/1/04 | Wed 12/28/05 |
| 19 | | Title IV - Acid Rain Permit | 65 days | Thu 3/3/05 | Wed 6/1/05 |
| 22 | | Title V - Operating Permit | 210 days | Thu 1/27/05 | Wed 11/16/05 |
| 25 | | Consumptive Use Permit or Water Use Permit | 120 days | Thu 1/27/05 | Wed 7/13/05 |
| 28 | | NPDES Generic Permit for Industrial Storm Water | 32 days | Thu 1/27/05 | Fri 3/11/05 |
| 31 | | NPDES Industrial Process Discharge Permit | 240 days | Thu 12/16/04 | Wed 11/16/05 |
| 34 | | Hydrostatic Discharge Authorization | 75 days | Thu 2/17/05 | Wed 6/1/05 |
| 37 | | NPDES Phase II Generic Permit for Construction Storm Water | 60 days | Thu 1/27/05 | Wed 4/20/05 |
| 40 | | 404 IP and Environmental Resource Permit | 360 days | Thu 7/1/04 | Wed 11/16/05 |
| 46 | | Coastal Zone Consistency Review | 120 days | Thu 1/27/05 | Wed 7/13/05 |
| 49 | | Threatened & Endangered Species Clearance | 156 days | Thu 7/1/04 | Thu 2/3/05 |
| 52 | | Tree Removal Permit | 93 days | Thu 7/1/04 | Mon 11/8/04 |
| 55 | | Phase I Cultural Resource Survey | 153 days | Thu 7/1/04 | Mon 1/31/05 |
| 58 | | Noise Abatement | 45 days | Thu 7/1/04 | Wed 9/1/04 |
| 61 | | Obstruction to Air Navigation | 65 days | Thu 7/1/04 | Wed 9/29/04 |
| 64 | | Storage Tank Registration | 35 days | Thu 6/1/06 | Wed 7/19/06 |
| 67 | | Spill Prevention Control and Countermeasure Plan | 108 days | Wed 2/1/06 | Fri 6/30/06 |




Project: Schedule_ProgressEnergy_Fl
Date: Thu 2/5/04

Task | Milestone | Rolled Up Split | External Tasks
Split | Summary | Rolled Up Milestone | Project Summary
Progress | Rolled Up Task | Rolled Up Progress

# Appendix D

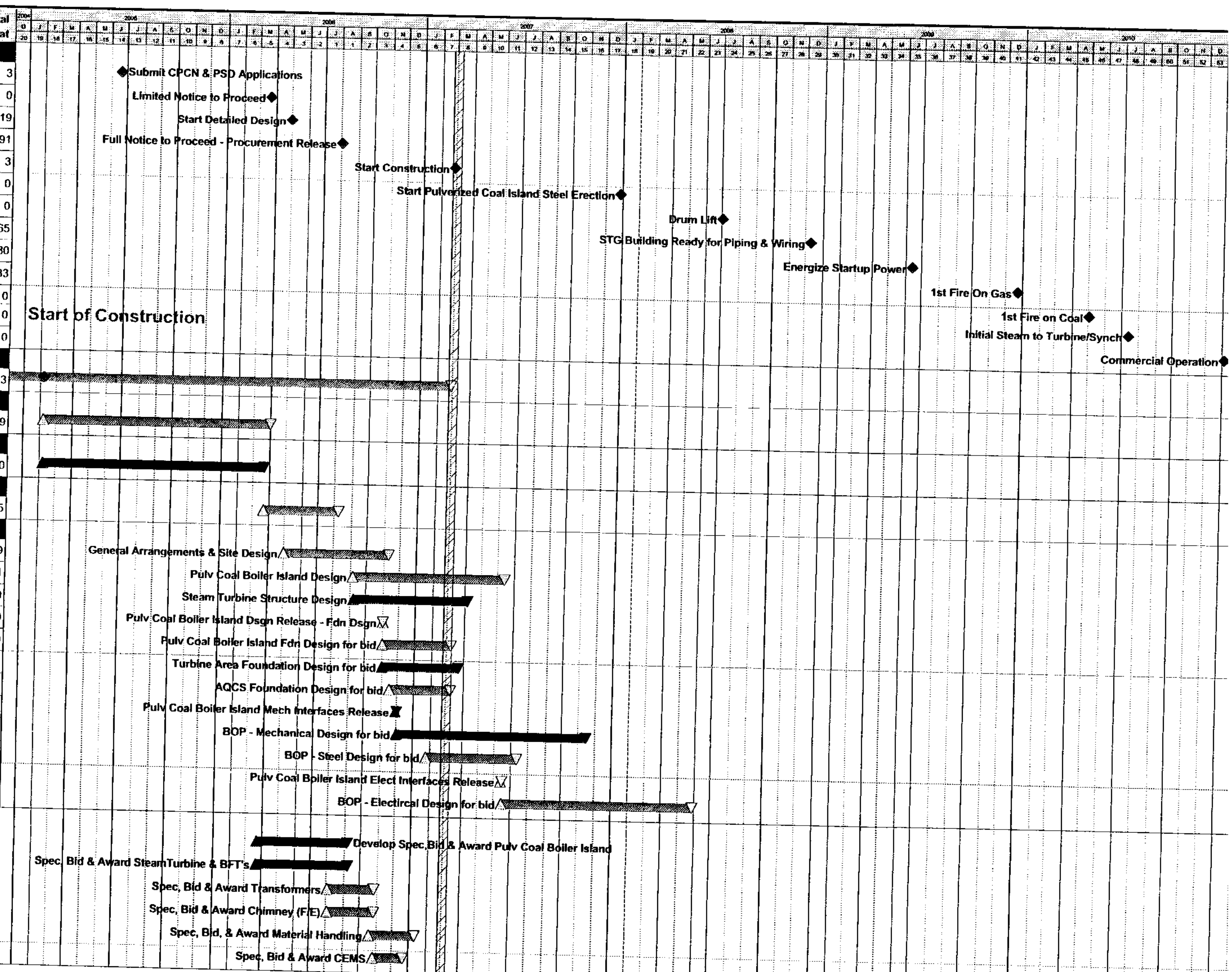





| | | |
|---|---|---|
| Burns & McDonnell SINCE 1898 | PROGRESS ENERGY | project 35076 |
| date | | contract |
| designed | 2 X 500 MW PC UNIT SITE LAYOUT | SK - |

# Appendix E

| Activity ID | Activity Description | Orig Dur | Early Start | Early Finish | Total Float |
|---|---|---|---|---|---|
| **Project Milestones** | | | | | |
| C61320 | Submit CPCN & PSD Applications | 0 | 20JUN05* | | 3 |
| C61005 | Limited Notice to Proceed | 0 | 22MAR06 | | 0 |
| C61010 | Start Detailed Design | 0 | 01MAY06* | | 19 |
| C61015 | Full Notice to Proceed - Procurement Release | 0 | 03AUG06* | | 91 |
| M0000 | Start Construction | 0 | 27FEB07* | | 3 |
| M0001 | Start Pulverized Coal Island Steel Erection | 0 | 27DEC07 | | 0 |
| M0015 | Drum Lift | 0 | 03JUL08 | | 0 |
| M0002 | STG Building Ready for Piping & Wiring | 0 | 11DEC08 | | 65 |
| M0003 | Energize Startup Power | 0 | 15JUN09 | | 30 |
| M0004 | 1st Fire On Gas | 0 | 22DEC09 | | 33 |
| M0005 | 1st Fire on Coal | 0 | 03MAY10 | | 0 |
| M0006 | Initial Steam to Turbine/Synch | 0 | 13JUL10 | | 0 |
| M0007 | Commercial Operation | 0 | 04JAN11 | | 0 |
| **+ Permitting** | | | | | |
| | | 976 | 02JUN03 | 26FEB07 | 3 |
| **+ Preliminary Engineering** | | | | | |
| | | 300 | 07FEB05 | 31MAR06 | 39 |
| **+ EPC Contract Procurement** | | | | | |
| | | 292 | 07FEB05 | 21MAR06 | 0 |
| **+ Rail Spur EPC Procurement** | | | | | |
| | | 100 | 22MAR06 | 08AUG06 | 65 |
| **Detailed Engineering** | | | | | |
| C61216 | General Arrangements & Site Design | 140 | 01MAY06 | 10NOV06 | 19 |
| C61050 | Pulv Coal Boiler Island Design | 200 | 06SEP06 | 12JUN07 | 1 |
| C61030 | Steam Turbine Structure Design | 150 | 07SEP06 | 04APR07 | 0 |
| C61051 | Pulv Coal Boiler Island Dsgn Release - Fdn Dsgn | 1 | 01NOV06 | 01NOV06 | 10 |
| C61211 | Pulv Coal Boiler Island Fdn Design for bid | 90 | 02NOV06 | 07MAR07 | 10 |
| C61212 | Turbine Area Foundation Design for bid | 100 | 02NOV06 | 21MAR07 | 0 |
| C61213 | AQCS Foundation Design for bid | 80 | 16NOV06 | 07MAR07 | 10 |
| C61052 | Pulv Coal Boiler Island Mech Interfaces Release | 1 | 29NOV06 | 29NOV06 | 0 |
| C61221 | BOP - Mechanical Design for bid | 250 | 30NOV06 | 14NOV07 | 0 |
| C61214 | BOP - Steel Design for bid | 120 | 24JAN07 | 10JUL07 | 77 |
| C61053 | Pulv Coal Boiler Island Elect Interfaces Release | 1 | 13JUN07 | 13JUN07 | 30 |
| C61217 | BOP - Electrical Design for bid | 250 | 14JUN07 | 28MAY08 | 30 |
| **Equipment Procurement** | | | | | |
| C61170 | Develop Spec,Bid & Award Pulv Coal Boiler Island | 120 | 22MAR06 | 05SEP06 | 0 |
| C61020 | Spec, Bid & Award SteamTurbine & BFT's | 121 | 22MAR06 | 06SEP06 | 0 |
| C61155 | Spec, Bid & Award Transformers | 60 | 03AUG06 | 25OCT06 | 135 |
| C61375 | Spec, Bid & Award Chimney (F/E) | 60 | 03AUG06 | 25OCT06 | 143 |
| C61243 | Spec, Bid, & Award Material Handling | 60 | 19OCT06 | 10JAN07 | 20 |
| C61235 | Spec, Bid & Award CEMS | 40 | 26OCT06 | 20DEC06 | 155 |






Burns & McDonnell SINCE 1898

PROG

**Progress Energy**

Sheet 1 of 3

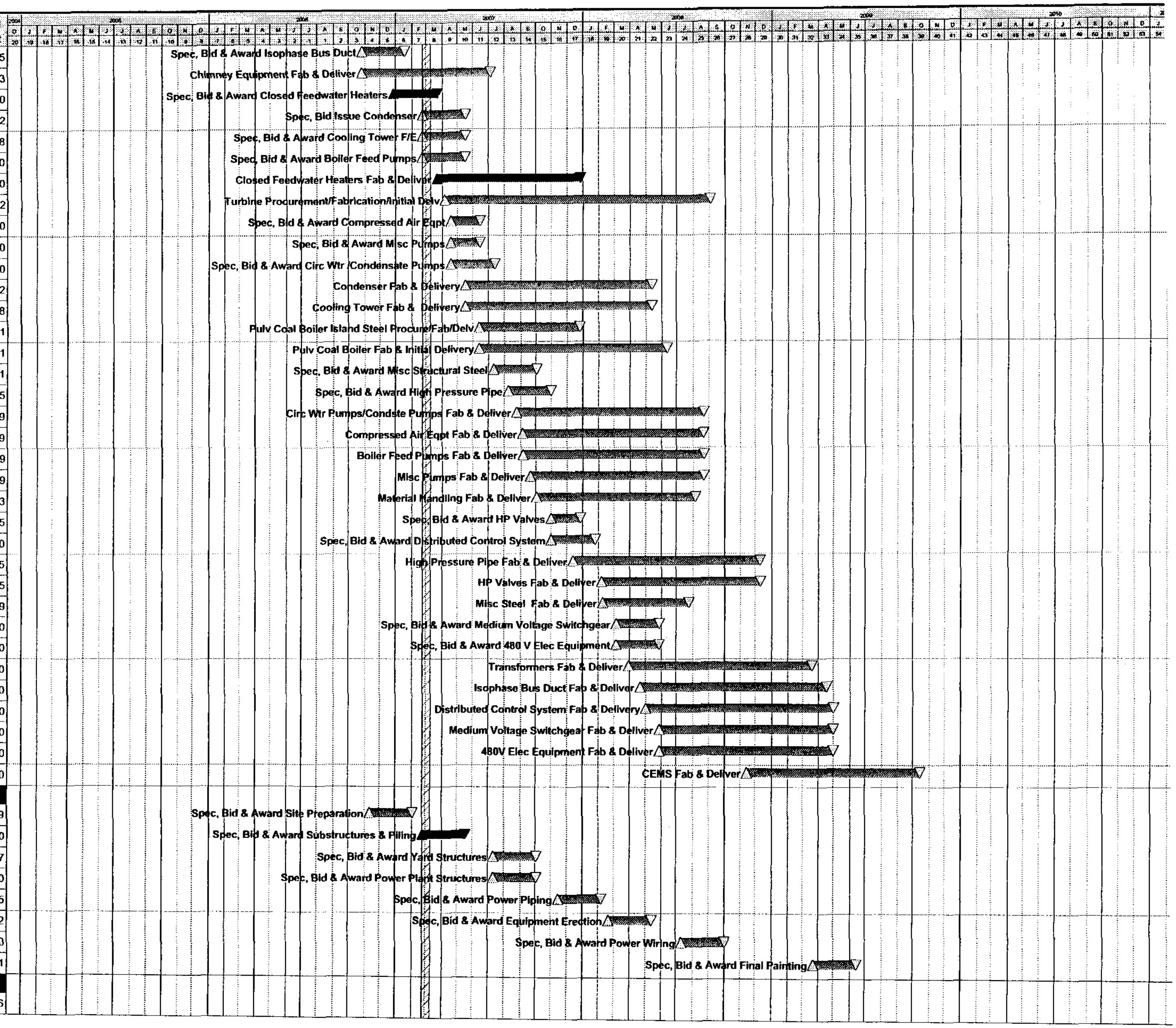
**Pulverized Coal Fired Power Plant**
**500 MW - Florida**

Notes:

1. Durations shown in business days with holidays excluded.

| Date | Revision | Checked | Approved |
|---|---|---|---|
| 21NOV03 | Initial | LKL | |

| Activity ID | Activity Description | Orig Dur | Early Start | Early Finish | Total Float |
|---|---|---|---|---|---|
| C61245 | Spec, Bid & Award Isophase Bus Duct | 60 | 26OCT06 | 17JAN07 | 135 |
| C61385 | Chimney Equipment Fab & Deliver | 180 | 26OCT06 | 04JUL07 | 143 |
| C61135 | Spec, Bid & Award Closed Feedwater Heaters | 60 | 28DEC06 | 21MAR07 | 0 |
| C61095 | Spec, Bid Issue Condenser | 60 | 22FEB07 | 16MAY07 | 122 |
| C61035 | Spec, Bid & Award Cooling Tower F/E | 60 | 22FEB07 | 16MAY07 | 128 |
| C61145 | Spec, Bid & Award Boiler Feed Pumps | 60 | 22FEB07 | 16MAY07 | 160 |
| C61136 | Closed Feedwater Heaters Fab & Deliver | 200 | 22MAR07 | 26DEC07 | 0 |
| C61040 | Turbine Procurement/Fabrication/Initial Delv | 370 | 05APR07 | 03SEP08 | 102 |
| C61125 | Spec, Bid & Award Compressed Air Eqpt | 40 | 19APR07 | 13JUN07 | 140 |
| C61105 | Spec, Bid & Award Misc Pumps | 40 | 19APR07 | 13JUN07 | 150 |
| C61218 | Spec, Bid & Award Circ Wtr /Condensate Pumps | 60 | 19APR07 | 11JUL07 | 110 |
| C61085 | Condenser Fab & Delivery | 260 | 17MAY07 | 14MAY08 | 122 |
| C61045 | Cooling Tower Fab & Delivery | 260 | 17MAY07 | 14MAY08 | 128 |
| C61054 | Pulv Coal Boiler Island Steel Procure/Fab/Delv | 140 | 13JUN07 | 25DEC07 | 1 |
| C61056 | Pulv Coal Boiler Fab & Initial Delivery | 260 | 13JUN07 | 10JUN08 | 21 |
| C61305 | Spec, Bid & Award Misc Structural Steel | 60 | 11JUL07 | 02OCT07 | 171 |
| C61265 | Spec, Bid & Award High Pressure Pipe | 60 | 09AUG07 | 31OCT07 | 95 |
| C61219 | Circ Wtr Pumps/Condste Pumps Fab & Deliver | 260 | 24AUG07 | 21AUG08 | 79 |
| C61126 | Compressed Air Eqpt Fab & Deliver | 250 | 07SEP07 | 21AUG08 | 79 |
| C61146 | Boiler Feed Pumps Fab & Deliver | 250 | 07SEP07 | 21AUG08 | 79 |
| C61106 | Misc Pumps Fab & Deliver | 240 | 21SEP07 | 21AUG08 | 79 |
| C61247 | Material Handling Fab & Deliver | 220 | 03OCT07 | 05AUG08 | 143 |
| C61255 | Spec, Bid & Award HP Valves | 40 | 01NOV07 | 26DEC07 | 95 |
| C61065 | Spec, Bid & Award Distributed Control System | 60 | 01NOV07 | 23JAN08 | 100 |
| C61266 | High Pressure Pipe Fab & Deliver | 260 | 13DEC07 | 10DEC08 | 65 |
| C61256 | HP Valves Fab & Deliver | 220 | 07FEB08 | 10DEC08 | 65 |
| C61306 | Misc Steel Fab & Deliver | 120 | 08FEB08 | 24JUL08 | 79 |
| C61205 | Spec, Bid & Award Medium Voltage Switchgear | 60 | 06MAR08 | 28MAY08 | 30 |
| C61225 | Spec, Bid & Award 480 V Elec Equipment | 60 | 06MAR08 | 28MAY08 | 30 |
| C61156 | Transformers Fab & Deliver | 255 | 31MAR08 | 20MAR09 | 30 |
| C61246 | Isophase Bus Duct Fab & Deliver | 260 | 21APR08 | 17APR09 | 30 |
| C61055 | Distributed Control System Fab & Delivery | 260 | 01MAY08 | 29APR09 | 30 |
| C61206 | Medium Voltage Switchgear Fab & Deliver | 240 | 29MAY08 | 29APR09 | 30 |
| C61226 | 480V Elec Equipment Fab & Deliver | 240 | 29MAY08 | 29APR09 | 30 |
| C61236 | CEMS Fab & Deliver | 240 | 13NOV08 | 14OCT09 | 30 |
| **Construction Subcontracts Procurement** | | | | | |
| C61275 | Spec, Bid & Award Site Preparation | 60 | 13NOV06 | 02FEB07 | 19 |
| C61285 | Spec, Bid & Award Substructures & Piling | 60 | 22FEB07 | 16MAY07 | 0 |
| C61395 | Spec, Bid & Award Yard Structures | 60 | 11JUL07 | 02OCT07 | 77 |
| C61315 | Spec, Bid & Award Power Plant Structures | 60 | 11JUL07 | 02OCT07 | 90 |
| C61335 | Spec, Bid & Award Power Piping | 60 | 15NOV07 | 06FEB08 | 65 |
| C61325 | Spec, Bid & Award Equipment Erection | 60 | 21FEB08 | 14MAY08 | 122 |
| C61345 | Spec, Bid & Award Power Wiring | 60 | 10JUL08 | 01OCT08 | 30 |
| C61355 | Spec, Bid & Award Final Painting | 60 | 23MAR09 | 12JUN09 | 81 |
| **Construction & Startup** | | | | | |
| C61089 | Tie-in DC Power Converter Station for Startup | 0 | | 30MAY03 | 1,566 |



| Activity ID | Activity Description | Orig Dur | Early Start | Early Finish | Total Float |
|---|---|---|---|---|---|
| C61061 | Construct Rail Spur for project | 256 | 09AUG06 | 01AUG07 | 65 |
| C61060 | Mobilization - Plant Site Construction | 20 | 27FEB07* | 26MAR07 | 3 |
| C61215 | Site Grading to Release Piling | 44 | 27MAR07 | 25MAY07 | 3 |
| C61228 | Construct Landfill (common) | 100 | 28MAY07 | 12OCT07 | 189 |
| C61220 | Piling & BOP Foundations & U/G Construction | 260 | 31MAY07 | 28MAY08 | 0 |
| C61222 | Pulv Coal Boiler Area Foundations | 120 | 12JUL07 | 26DEC07 | 0 |
| C61224 | Steam Turbine Area Fdn and Pedestal | 180 | 26JUL07 | 02APR08 | 79 |
| C61062 | Tie-in Railroad to Plant Site for Eqpt Delivries | 0 | | 01AUG07 | 65 |
| C61370 | Construct Chimney Shell & Liner (common) | 260 | 20SEP07 | 17SEP08 | 88 |
| C61070 | Pulv Coal Boiler Steel Erection to Drum Lift | 135 | 27DEC07 | 02JUL08 | 0 |
| C61164 | Construct AQCS Area Foundations | 120 | 07FEB08 | 23JUL08 | 128 |
| C61274 | Construct Yard Structures and Foundations | 200 | 19MAR08 | 23DEC08 | 77 |
| C61075 | ST Bldg Steel Erection & Slabs | 101 | 03APR08 | 21AUG08 | 79 |
| C61078 | Erect Condenser /Slide under Pedestal | 60 | 15MAY08 | 06AUG08 | 122 |
| C61280 | Erect Cooling Tower | 227 | 15MAY08 | 27MAR09 | 128 |
| C61149 | Lft Steam Drum | 5 | 03JUL08 | 09JUL08 | 0 |
| C61072 | Pulv Coal Boiler Building Slabs & Enclosures | 300 | 03JUL08 | 26AUG09 | 15 |
| C61150 | Pulv Coal Boiler Erection | 365 | 10JUL08 | 02DEC09 | 0 |
| C61178 | Construct Fly Ash Silo | 160 | 06AUG08 | 17MAR09 | 166 |
| C61281 | Construct Coal Silos | 256 | 06AUG08* | 29JUL09 | 77 |
| C61276 | Erect Material Handling Facilities | 270 | 06AUG08 | 18AUG09 | 143 |
| C61330 | BOP Mechanical Equipment Erection | 200 | 22AUG08 | 28MAY09 | 79 |
| C61080 | Steam Turbine Erection | 320 | 04SEP08 | 25NOV09 | 102 |
| C61176 | AQCS Stl & Eqpt Erection | 315 | 13OCT08 | 25DEC09 | 71 |
| C61230 | Pulv Coal Boiler Area Mech Eqpt & Piping | 355 | 16OCT08 | 24FEB10 | 15 |
| C61240 | BOP Power Piping | 250 | 11DEC08 | 25NOV09 | 65 |
| C61250 | Pulv Coal Boiler Area Elec Eqpt & Wiring | 320 | 15DEC08 | 05MAR10 | 0 |
| C61290 | BOP Elec Eqpt & Wiring | 250 | 22JAN09 | 06JAN10 | 30 |
| C61090 | Energize Startup Power | 0 | 15JUN09 | | 30 |
| C61332 | Apply Final Painting | 200 | 15JUN09 | 19MAR10 | 81 |
| C61270 | Water System Commissioning | 40 | 13JUL09 | 04SEP09 | 33 |
| C61232 | Insulation and Lagging | 200 | 23JUL09 | 28APR10 | 15 |
| C61110 | Pulv Coal Boiler Hydro | 11 | 05OCT09 | 19OCT09 | 33 |
| C61120 | Pulv Coal Boiler/Ash Systems Commissioning | 95 | 20OCT09 | 01MAR10 | 44 |
| C61115 | Perform Pulv Boiler Coal Boilout | 12 | 22DEC09 | 06JAN10 | 33 |
| C61100 | Turbine Commissioning | 61 | 07JAN10 | 01APR10 | 72 |
| C61260 | Coal Handling Syst Commissioning | 40 | 08MAR10 | 30APR10 | 0 |
| C61195 | AQCS Commissioning | 70 | 08MAR10 | 11JUN10 | 21 |
| C61165 | 1st Fire on Coal | 0 | 03MAY10 | | 0 |
| C61166 | Steam Blow | 18 | 20MAY10 | 14JUN10 | 0 |
| C61130 | Initial Energy | 0 | | 12JUL10 | 0 |
| C61160 | Tuning, Performance & Availability Testing | 125 | 13JUL10 | 03JAN11 | 0 |
| C61140 | COD | 0 | | 03JAN11 | 0 |