BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Expansion of an Electrical Power Plant, for Exemption from Rule 25-22.082, F.A.C., and for Cost Recovery through the Fuel Clause

DOCKET NO. 060658
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DIRECT TESTIMONY OF JAMES N. HELLER ON BEHALF OF PROGRESS ENERGY FLORIDA

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IN RE: PETITION ON BEHALF OF CITIZENS OF THE STATE OF FLORIDA TO REQUIRE PROGRESS ENERGY FLORIDA, INC. TO REFUND CUSTOMERS $143 MILLION

FPSC DOCKET NO. 060658

DIRECT TESTIMONY

JAMES N. HELLER

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is James N. Heller. My address is 4803 Falstone Avenue, Chevy Chase, Maryland.

Q. How are you employed?

A. I am the President of Hellerworx, Inc.

Q. What do you do?

A. I provide consulting services to assist power generators, transportation companies and energy producers in solving economic and technical problems related to energy and transportation markets and environmental compliance issues.

Q. Have you been retained by Progress Energy Florida (PEF) in this proceeding?

A. Yes.

Q. What were you asked to do?

A. I was asked to review the coal market conditions, during the period 1996-2005, review the solicitations conducted by PEF during this period and the market responses, and provide my own analysis of the economics of blending Powder River Basin ("PRB") coal at Crystal River units 4 and 5 (CR4 and CR5) during this time period. In addition, I have been asked to review the testimony and respond to the damages calculation presented by Mr. Sansom with regard to his allegations that PEF should have switched a portion of its coal supply to the PRB during the 1996-2005 time frame.

Q. What is your educational background?

A. I have a Bachelor of Science degree in Electrical Engineering from Northwestern University (1970) and a Master of Business Administration from Harvard Business School (1972).

Q. What has been your professional experience that assists you in providing this testimony?

A. During my career, I have performed numerous studies and provided information and consulting services for electric utilities, energy companies, developers and transportation companies related to coal and coal transportation markets. I have worked for many electric utilities in Florida on matters related to coal and transportation procurement including new plant siting.

I have analyzed central Appalachia and Powder River Basin coal markets on numerous occasions. I have assisted clients in the negotiation of coal and transportation contracts, in the analysis of coal supply and transportation alternatives, and in strategic planning matters related to environmental compliance and fuel procurement.

Aside from my work with electric generators and coal suppliers, I have also worked for the Electric Power Research Institute and various federal agencies on coal supply and transportation related studies. I have provided expert testimony on coal market matters before various state commissions, federal courts, the Federal Energy Regulatory Commission, the US Surface Transportation Board and various domestic and foreign arbitration panels.

I have done work previously for Florida Power Corporation, Progress Energy and Electric Fuels. Some of this previous work has dealt with coal supply and transportation related to the Crystal River units.

II. PURPOSE, SUMMARY AND APPROACH TO TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to analyze the results of the decisions that PEF made with regard to purchasing coals during the 1996-2005 time period and to determine whether the customers would have benefited from PEF having burned a blend of PRB coal at CR4 and CR5. I have then addressed certain allegations made by Mr. Sansom in his testimony filed in this case on October 19, 2006. These allegations include the following:

- PEF's coal procurement policies were flawed;
- PEF should have purchased PRB coal during the period 1996-2005; and,
- If PEF had purchased PRB coal during this time period, the fuel savings would have been $134 million.

Q. How did you approach these issues and on what materials did you rely?

A. I first requested data responses and materials provided by the Company with regard to their prior coal solicitations, responses to those solicitations, and analysis of solicitation results. I requested information on coal contracts that were applicable during this period. I requested information about any analyses conducted by the Company with regard to the use of PRB at Crystal River and the likely impact. I requested and reviewed information on coal transportation costs and the transportation market proxy. I held discussions with various current and former PEF staff members and posed questions about the procedures that they used to consider and evaluate PRB coals. I also reviewed various discovery responses, including responses provided by the Office of Public Counsel (OPC). In addition to the materials received from PEF, I gathered information from coal publications and data bases about PRB coal market prices and transportation rates during the 1996-2005 time frame. This is the type of information with which I work regularly.

Q. What analysis did you perform with the materials that you collected?

A. I developed a model to compare the incremental costs to CR4 and CR5 of coal actually purchased and delivered to the units with the cost of PRB coal on an "as-burned" basis. In other words, if PEF purchased PRB coals for CR4 and CR5, the PRB shipments would have displaced other coals. Presumably, the coals displaced would have been those that were the highest prices coals delivered to the units that were not under term contracts. I then calculated the difference in the incremental costs of the delivered coals and the PRB coals on an "as-burned" basis.

Q. How did you perform the analysis?

A. I reviewed the delivered prices of coal to Crystal River during the period 1996-2005 and identified the mix of coals burned at the plant. I identified which of the coals were under contract and when those contracts expired. If the coal contracts were executed prior to 1996, then I assumed that those contracts would be honored until their expiration. I reviewed information as to whether the coals were delivered by rail or water. I also considered the delivered price of the coals actually delivered. These coals were either from central Appalachia (CAPP) or were imports from South America. Central Appalachia refers to a coal supply region including eastern Kentucky, West Virginia, Virginia and Tennessee which is the primary eastern US low sulfur bituminous coal producing region. I ranked these deliveries over time in terms of their delivered costs. I also examined the results of bid solicitations conducted by PEF between 1996 and 2005 to determine how PRB coals would have compared with the selected coals.

Q. Did you perform the analysis on a delivered price or "evaluated" price basis?

A. I performed the comparisons on an "as-burned" or "evaluated" price basis. This is because in comparing coals of very different characteristics, it is important to understand how they affect boiler operations and unit output. A relatively low Btu, high moisture coal like a PRB coal generally has a negative impact on boiler performance while its lower sulfur content has a positive impact on emissions. PEF analyzed these differences in coal quality characteristics and calculated adjustments to evaluate these differences and express them on a cents per million Btu basis. I was able to use these differences or follow the methodology used in calculating the differences to compare the different coals. I also considered other factors that would have constrained the amount of PRB coal that could be purchased and delivered including, for example, transport capacity and existing contractual commitments.

Q. Please provide a summary of your testimony.

A. PEF's coal procurement policies and practices during the relevant time period from 1996 to 2005 were not flawed. PEF employed formal solicitations for term coal contracts and informal "spot" purchases to procure coal by rail or water for the Crystal River coal units, in particular CR4 and CR5, consistent with the physical limits imposed by the site, industry practice, and the Commission's policies.

PEF should not have purchased PRB coal during the period 1996-2005, as OPC alleges in its petition and Mr. Sansom's testimony. PEF evaluated coal of a different type and quality from the specifications for the Crystal River units to obtain the lowest "evaluated" or "busbar" price. The "evaluated" or "busbar" price includes the coal commodity costs, all transportation and handling costs to the coal units including blending, and any additional operation and maintenance (O&M) costs due to the impact of variations in the quality of the coal on boiler operations. On an "evaluated" or "busbar" price comparison between PRB and bituminous coals the PRB coals were not economic until 2004 and 2005 when higher sulfur dioxide (SO_2) prices and substantial increases in CAPP and import bituminous coals caused the PRB coals to appear to be more economic for CR4 and CR5. This is exactly the point when the Company reasonably and prudently reacted by conducting test burns and evaluating a switch to PRB coals or a blend of PRB coals with bituminous coals.

The use of an "evaluated" price in making coal procurement decisions is a reasonable, prudent industry practice; in fact, PEF employed a widely used industry model for coal quality impacts to develop its "evaluated" or "busbar" price. It is also common industry practice to establish typical or expected coal specifications for coal units. Differences in coal quality can affect the actual cost of using the coal at the coal units and plant efficiency. Because CR4 and CR5 are base load units that I understand operate above their original design capacity in terms of unit output, the impact of coal quality on unit performance would be especially important. Using a model to evaluate the impact of coals with different qualities then --- which was certainly the case for PRB coals compared to the CAPP and import bituminous coals typically burned at the units --- was a reasonable and prudent consideration for PEF consistent with industry practice and standards.

If PEF had purchased PRB coals to blend with bituminous coals during the period from 1996-2005, as OPC alleges should have been done, there would not have been fuel savings of $134 million. Existing contractual and delivery constraints and delivery delays PEF would have faced must be taken into account. Additionally, the actual commodity and transportation and handling costs that would have applied to PEF, rather than some other or hypothetical entity, must be considered. Further, capital would have been required to allow the units to blend, and burn, PRB coal. The savings from the PRB blend would need to exceed the capital required to permit the blending and burning of PRB coal in the units. When this "threshold" capital and O&M cost is considered and all other costs are calculated correctly, customers would have paid much more for the PRB coal blends than they otherwise actually paid from 1996 to 2005. In 2004 and 2005, the change in relative coal and transportation costs may have made PRB coals an attractive alternative, and PEF was analyzing such blending opportunities during this time. That PEF did not focus on the complex process of evaluating and undertaking a fuel switch decision, which can take years, until 2004 when the comparative prices warranted such an undertaking is reasonable. Therefore, there is no reasonable basis to conclude that customers would have received savings based on a hypothetical decision to undertake and complete a coal switch at any earlier period of time.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits that I have prepared or that were prepared under my supervision and control:

- Exhibit No. __ (JNH-1), which is a description of the CQIM model;
- Exhibit No. __ (JNH-2), which is a graph depicting PRB coal prices for the relatively high (8,800 Btu/lb. coals);
- Exhibit No. __ (JNH-3), which is a graph depicting the prices of SO_2 allowances;
- Exhibit No. __ (JNH-4), which is a PEF document entitled "Estimated Powder River Basis Origin Market;"
- Exhibit No. __ (JNH-5), which shows the added capital and operating cost for PRB use at CR4 and CR5;
- Exhibit No. __ (JNH-6), which is a summary of PRB delivered and evaluated prices;
- Exhibit No. __ (JNH-7), which is an economic analysis of PRB substitution impacts; and
- Exhibit No. ___ (JNH-8), which is a chart of the higher costs to customers had PEF burned the PRB blend suggested by OPC at CR4 and CR5, together with the SO_2 allowance and de-rate valuations prepared by PEF witnesses, Mr. Dean and

Mr. Crisp.

All of these exhibits are true and correct to the best of my knowledge.

III. COAL PROCUREMENT FOR CRYSTAL RIVER 1996-2005

Q. What is your understanding of the Crystal River complex?

A. The Crystal River complex consists of four coal-fired units and one nuclear power plant. Units 1 and 2 (CR1 and CR2) are earlier units subject to less stringent emissions standards. CR4 and CR5 were built and achieved commercial operation in 1982 and 1984, respectively. These units were subject to the EPA New Source Performance Standards (NSPS) and were required to burn coal with a sulfur content of less than or equal to 1.2lb. SO_2/MMBtu. Units subject to NSPS requirements which do not use scrubbers ("flue gas desulphurization" units) must purchase coals of very low sulfur content.

Q. What types of coals are burned at the plant?

A. PEF uses two general types of coal. An "A" coal specification is used for coals burned at units 1 and 2. A "D" compliance coal specification is used for coals burned at units 4 and 5. Because units 4 and 5 were put in service later than units 1 and 2, they were subject to the more stringent NSPS which specified a lower sulfur content than was acceptable for units 1 and 2.

Q. How is coal delivered to the Crystal River complex?

A. Crystal River is accessible by CSX rail-direct and via barge. The use of barge delivery creates competition for CSX. Absent competition from waterborne coals, CSX would enjoy a monopoly position for coal deliveries to the plant. Since PEF takes delivery of coal both by rail and water, CSX's market power is diminished.

Direct rail shipments of coal originate in central Appalachia and are moved primarily in PEF owned or leased rail equipment to the plant. PEF can also originate certain CAPP coals by barge, transport them to the International Marine Terminals (IMT) coal transfer facility located near New Orleans, and then via ocean-going barge across the Gulf for delivery to the plant. PEF can further receive foreign coals through IMT. The IMT coal transfer facility, which was partly owned by PEF, is a large port capable of receiving coals by river barge or ocean going vessel, storing and blending the coals, and then transferring them to the ocean-going barges that serve Crystal River. This waterborne capability also provides the best potential for Crystal River to receive PRB coals.

Q. Are there any limitations on rail and water deliveries to the plant?

A. Yes. CSX moves coal south to Crystal River in unit trains from mines located primarily in Kentucky, Virginia, and West Virginia. While most of the coal movement is over CSX mainline, the final segment of delivery to the plant traverses a piece of single line track from Dunnellon, Florida to Red Level Junction, which is the plant site.

This single track limits the number of trains that can be efficiently moved into and out of the plant site. Typically PEF operates 7-8 unit train sets. At times when CSX has failed to meet delivery schedules, PEF has placed additional 4-5 trainsets into service to make up the shortfall. When this has occurred, PEF has experienced additional congestion and has concluded that the additional demurrage charges have offset the benefits of adding additional train sets.

While the waterborne option provides competition for CSX and has likely kept rates from rising to the levels of other captive shippers, it also has limitations. The Crystal River channel has a draft constraint of approximately 20 feet which limits the capacity of the tug-barge tows used in this service to generally about 16,000 tons per barge. In addition, the tight turning basin at Crystal River and channel constraints limit the number of shipments that can be taken by water to the plant to about 2.4 million tons per year (MMtpy). While PEF has attempted to exceed this amount, operational problems have been encountered which have lead to the current 2.4 MMtpy capacity estimate.

This limitation on the waterborne delivery capacity is significant when the delivery of PRB coal to Crystal River is contemplated. Because PRB has a lower Btu content per ton than CAPP coal, replacing water deliveries of CAPP coal with PRB coal reduces the proportion of total Btu's of fuel delivered by water to the plant. To achieve the same Btu's of fuel with PRB coal more tons of PRB coal must be delivered, however, because only 2.4 MMtpy of coal can realistically be delivered to Crystal River by water there is a physical constraint on PRB coal deliveries by water to the Crystal River site.

Q. Which coals are delivered by rail and which by water?

A. The plant can receive either "A" or "D" coals by rail or water. Because the number of CAPP low sulfur coal sources are more limited for "D" coals, it is likely that they would be received by whichever means provides the lowest delivered cost. Since PEF has more flexibility in finding "A" suppliers it can switch between rail and water more readily. In addition, imported coals, which are generally "D" quality, also can only be received by water since they are shipped to the United States from South America by ocean going vessels or barges. PRB coals would also meet the "D" sulfur specification and would be most economically received by water. Theoretically the coal could move all rail, however, it would be one of the longest rail movements of coal in the United States. Shipping PRB coal all-rail to Crystal River would almost certainly be more costly than a combined rail-water movement. Between 1996 and 2005 over 95% of the coals delivered to IMT for Crystal River met the compliance coal specification. Thus in shipping PRB coal to Crystal River, the coals displaced would likely be higher Btu compliance coals.

Q. What have been the annual coal burns for Crystal River?

A. Crystal River units 1, 2, 4 and 5 are base load units. The plant received an average of 5.6 (MMtpy) of coal between 1996 and 2005. Of that total about 3.6 MMtpy were delivered by rail with the amount per year ranging between 3 and 4 million tons in any given year. Waterborne deliveries to IMT ranged between 1.7

and 2.6 MMtpy with an average of about 2.3 MMtpy.

Q. Does PEF have coal quality specifications for the Crystal River units?

A. Yes. For the general type of coal, PEF uses four set of specifications to determine the coal qualities purchased. For units 1 and 2 they use a "little box" and a "big box" specification and the same for units 4 and 5. For units 4 and 5 the "little box" specification allows spot coals with a Btu content of 12,000 Btu/lb. or more and meeting a series of other specifications, including the compliance coal specification of 0.6lb. S/MMBtu, to be delivered to Crystal River "without prior approval or acceptance of Fossil Plant Operations." Under the big box specification, coals with a Btu content of 8,910 or more and meeting the compliance coal sulfur specification are to be "evaluated" to determine their acceptability.

The notion of setting coal specifications that allow the coal purchasing group to evaluate various coals is common practice in the industry. All coals are not the same, and variations in various quality characteristics of the types of coal, such as the Btu, sulfur, moisture, ash, and volatile content of the coal, have an impact on the cost of using that type of coal, the efficiency of the boiler, and emissions requirements.

Q. What type of coal has PEF historically used at the CR4 and CR5 units to meet these coal specifications?

A. PEF has historically used and burned domestic and foreign compliance bituminous coal or bituminous-based synfuel at CR4 and CR5. The procurement of a western sub-bituminous coal like PRB therefore would have represented a significant switch of coal sources for the CR4 and CR5 units.

Q. What are considerations for switching coal sources?

A. Normally when a utility company decides to switch to very different coal sources it is because "opportunity" coals become available, coals from a different region become lower cost, or changes in environmental regulations require a switch. The change in environmental regulations may make it advantageous to switch to a lower sulfur sub-bituminous western coal, for example, to avoid violating permit restrictions, buying emission allowances, or installing expensive pollution controls. Before making a switch in coal sources, however, the utility company typically engages in detailed tests and evaluations including test shipments and test burns. In this case, the PRB specifications are outside even the "big box" specifications for CR4 and CR5 and would likely have called for such analysis and testing.

In addition to the analysis and testing of the new coal source, such as a switch to PRB coals, the utility company must evaluate the logistics of receiving the new coal including the purchase of larger railcars which are capable of handling the coals over long distances, transloading facilities if water movements are involved, and the development of blending facilities if multiple coals are to be used. The analysis includes the impact on unit operations, for example, to determine if a de-rate will occur. A de-rate is a loss of unit output. Any capital investments required at the plant site to handle the new coals, such as sub-bituminous coals, must also be analyzed along with the impact on flyash and bottom ash and their marketability. Flyash and bottom ash are sold by the utility for other uses, such as in asphalt; and if the ash quality is impacted to the extent it is no longer marketable the utility will face the additional cost of ash disposal.

It is, therefore, not just the delivered price of the fuel that ultimately determines whether the plant will make a fuel switch but the analysis of these multiple factors and how they are likely to change over time. In other words, given the difficulty of switching fuels, the utility wants to be relatively certain that the decision will allow for repayment of any invested capital and that the savings from a fuel switch will also offset all additional cost impacts.

IV. PEF COAL PROCUREMENT POLICY

Q. Did PEF have a coal procurement policy during this period?

A. Yes. In 1987 PEF published "Electric Fuels Corporation Coal Procurement Procedures." Under these guidelines, PEF procured coals using a portfolio of short and long term contacts from multiple producers of varying coal qualities delivered by rail and water.

The duration of the contracts varied but included 20-year agreements with Massey and Powell Mountain Joint Venture (PMJV) as well as other 10 and 15 year agreements. The portfolio also included numerous spot agreements and short term contracts. In addition, some contracts contained options that allowed PEF to adjust coal deliveries based on fluctuations in coal burn, deliveries, and inventories.

This approach to purchasing coal from a variety of sources and using contracts of various durations was typical of sophisticated coal buyers in the industry. Usually companies maintain 70-85% of their coal deliveries under term agreements. During the 1980's it was common for long term agreements to be ten years or longer. This reflected the need for new mines to be financed by long term contracts, and power plants to have guaranteed coal supplies. In the 1990's, it was common to shift into shorter term agreements, often 3-5 years. Market price reopeners were used to ensure that contract and spot prices did not deviate significantly for long periods of time. It also became common to quote prices in fixed terms and without complex price escalation provisions.

In 2001, however, a price spike occurred and PRB spot prices, for example, briefly and substantially exceeded contract prices for the first time in many years. While coal buyers have continued to purchase coal under a portfolio of contract terms, recent market volatility has again caused substantial deviations in spot prices and the prices under contracts that may have been recently signed.

The Florida Public Service Commission (PSC or Commission) had also indicated the desirability of having a high proportion of coal under long term contracts. This is not uncommon as commissions seek to protect customers from the spot market fluctuations which cause volatility in fuel costs and hence electric rates to customers.

Q. Did the policy address coal transportation?

A. Yes. The PSC also indicated that it was desirable for PEF to maintain both rail and waterborne delivery options. Recognizing that waterborne transport was generally more costly than rail, PEF's policy was to maximize its rail deliveries and take the remainder by water.

Q. How did PEF determine the mix of coals and transportation to buy each year?

A. PEF had two preliminary steps in the annual coal procurement process. First, the Company would estimate the annual coal burn at CR4 and CR5, and determine whether any inventory adjustments were desired. They would then determine the expected coal receipts under existing contractual commitments. The difference between the forecast burn, the inventory adjustment, and the pre-committed deliveries was the additional coal to be purchased over the forecast period. This approach was reasonable and consistent with industry practice.

Q. How did the Company purchase coal?

A. PEF issued formal requests for proposals (RFPs) for coal purchases or made informal purchases on the spot market. The spot market generally refers to informal offers typically of one year or less. The bids in response to the RFP were and are submitted, evaluated and then ranked according to their delivered and evaluated prices measured in cents per MMBtu delivered to Crystal River.

For coals that were similar in quality, the delivered price of the coal could serve as a useful ranking tool. However, for coals like PRB that were significantly different than the "spec coals," an evaluated analysis would be necessary.

As I mentioned, this "evaluated" or "busbar" price is based on an evaluation of the quality of the coal relative to a design coal specification for the unit. The bid coals may meet the company's overall specification, but not be of the same quality. These differences in quality can affect the actual cost of using the coal at the plant including the plant efficiency and the generation or use of emission allowances after 2000 when such allowances became a factor due to changes in environmental requirements. Emission allowances refer to the need to maintain overall sulfur emissions at permitted levels. Plants that generate less than their permitted emissions level can earn emission allowances. These excess allowances can be banked or sold to other companies. Therefore coals which contain lower sulfur levels are evaluated as having greater value than higher sulfur coals based on the value of the traded emission allowances.

PEF would then choose that mix of coals which would minimize the overall evaluated fuel costs considering the types of coals needed and the ability of the suppliers to ship by rail or water.

Q. How did PEF evaluate coals for the "evaluated" or "busbar" price?

A. The Company uses the Coal Quality Impact Model (CQIM), as updated, which was developed for the Electric Power Research Institute (EPRI) by Black & Veatch and introduced to determine the impact of variations in coal quality upon generation costs. This model or an equivalent is widely used for performing such analyses. It was developed for "evaluating Clean Air Act compliance strategies, evaluating bids on coal contracts, conducting test burn planning and analysis" among other functions. See Exhibit No. __ (JNH-1). In my experience, this is the model relied upon by companies in the industry who do the most sophisticated analysis of coal quality impacts on boiler operations.

Because the Company generally burned central Appalachian coals that were similar in quality characteristics, however, they could simply evaluate these CAPP coal bids on a delivered price basis and choose the lowest cost bids. Since the Company was purchasing coal and transportation from affiliates, the approach of ranking coals on a least cost delivered basis made the evaluations more transparent and less subject to criticism that somehow the process was being manipulated to favor affiliate coals.

The testimony of Mr. Hatt describes in more detail the relationship between coal quality and unit performance.

Q. Did PEF solicit PRB coals?

A. Yes. It is clear that PEF had solicited bids for PRB coals since at least 1998. The bid solicitations explicitly contain provisions for sub-bituminous coals and the bidder lists and bid response lists include producers of PRB coals.

Q. Were PRB bids submitted and evaluated in 1998?

A. No. In the 1998 RFP, respondents on the bidder response list like Kennecott and Peabody produced PRB coals. There were, however, no PRB bids submitted in response to the 1998 RFP and thus no evaluation of PRB coals as a result of that RFP.

In the same year, however, a memo by Dennis Edwards in February of 1998 demonstrates PEF was aware of PRB coals and had been following the PRB prices in the coal market. In the memo Mr. Edwards predicts "that we will, in all likelihood, be using Powder River Basin coals at 4 & 5 by about 2000 (my guess)." In regard to whether PEF should switch its D coal deliveries to rail, he notes that the required investment in rail equipment would be unwise if the traffic were to be shifted to PRB and other waterborne coals like South American bituminous compliance coals.

Q. What about the subsequent solicitations, were PRB coals solicited and bids received and evaluated?

A. Yes, they were solicited, and they were received for some of the solicitations and evaluated. In April 2001, bids were solicited and PEF received PRB bids for Triton's Rochelle and Buckskin mines coals. The timing of the PEF solicitation caught the peak of the PRB 2001 coal price spike. <u>See</u> Exhibit No. __ (JNH-2). The bids received were very high relative to the alternate coals even though the average PRB prices for 2001 were much lower than the bids received. Had PEF contracted for PRB coal at that time in 2001 for the prices bid, it would have been much more expensive than their other options.

Bid solicitations were also conducted in July 2003, May 2004, October 2005, and February 2006. In the July 2003 evaluation, a series of western coals were marked as "FOR TEST PURPOSES ONLY-Review Later" indicating that the Company was considering these coals. The relatively low SO_2 allowance prices at the time of $160/ton, however, meant that the low sulfur benefits of the western coal were not sufficient to offset the low Btu content, and the 8800 Btu coals generally carried an evaluated penalty of about $.15/MMBtu, which was much greater than the CAPP or import coals. SO_2 prices during this period are shown in Exhibit No. __ (JNH-3).

In the 2003 RFP analysis, the import coals are sold based on a 1.2lb. SO_2 specification, but actually deliver even lower sulfur, which makes them somewhat more attractive than a simple bid comparison might indicate. On an evaluated basis, however, the imported coals selected ranked lower than the PRB coals. PEF was also sensitive to the western rail delivery problems, which were causing concerns with deliverability of PRB coal in the period of time during which PEF was considering PRB coal.

PRB coal bids were collected in the subsequent May 2004 RFP and, as a result of those bid responses, PEF continued work it began after the 2003 RFP on conducting test burns, evaluating the possible switch to PRB coals or a blend with PRB coals, and permitting the units to burn the sub-bituminous coals.

In the 2005 solicitation, however, no PRB producer provided a bid in response to the RFP although, like before, PRB producers were sent the solicitation. PEF also received only one PRB coal bid from a coal broker in response to the 2006 solicitation and it was not competitive.

Q. How would companies evaluate PRB coals?

A. In the case of PRB, or lower Btu imported coals, the coal quality would vary significantly from the central Appalachian coals. In this case, the delivered price analysis could vary significantly from the "evaluated" price and the evaluated price would be the appropriate way to do the comparison. For example, a typical PRB coal would have a Btu content of 8,800 Btu/lb. while a CAPP coal could have a 12,000 or higher Btu/lb. heating value. The lower heating value of the PRB coal is due in part to much higher moisture content, which generally carries a heat penalty in the boiler. However, the PRB coal will typically carry a sulfur content of 0.8lb. SO_2/MMBtu while the CAPP coal value may be 1.2lb. SO_2/MMBtu. This difference in sulfur content can be easily monetized. When SO_2 allowances are $1,000/ton, the difference is worth about $.20/MMBtu while with prices at $200/ton it is worth only $.04. All of these differences are significant and can affect the coal evaluations. However, it appears that PEF's calculations of the PRB evaluated costs were more conservative estimates until PEF became further focused on the PRB option in 2003.

In addition, if the lowest evaluated coal price was PRB coal, the Company would need to consider whether a switch from the current blend of coals burned at the plant to a mix including PRB would require additional investment. In that case, the "threshold" differential between the evaluated prices of the CAPP coals and the PRB blend coals would need to be analyzed to determine if it was economic to justify switching. If the differential was not large enough or was not expected to be sustained in the future, the additional capital and operating costs required to switch might not be justified. Such analyses were often performed by companies faced with the prospect of switching to PRB coals. These are the types of "threshold" considerations that attend a major fuel shift.

Q. Are you familiar with other companies that have shifted coal sources between coal basins?

A. Yes. These are usually extensive efforts that occur over an extended period of time and involve input from numerous disciplines including groups responsible for finance, fuels, generation operations, environmental compliance, and regulatory matters. The fuel shifts usually occur over an extended period of time after the company has satisfied itself that the economics are compelling, tested the fuels, and decided which blends are appropriate, installed the necessary capital and procured the fuel and transportation.

Q. Have you had experience in working with companies in evaluating fuel switching?

A. Yes. I have worked on many such conversions including the analysis of alternative coal supplies and logistics. I have often worked as part of a team in conducting such analyses, often driven by Clean Air Act changes. Examples of such projects included Empire District Electric Company, Associated Electric Cooperative, Consumers Power, Dayton Power & Light, Duke Power, Illinois Power Company, Muscatine Power, Northern Indiana Public Service Company, Ontario Hydro, and TVA. Most of these companies were switching from existing coal sources to Powder River Basin coal and I would work on some portion of their effort to evaluate and/or implement alternatives.

Q. Did PEF perform such analyses?

A. Yes. There are a number of documents in 2005 and 2006 indicating that PEF undertook a series of analyses to test PRB coals and evaluate their impact on the boiler. This included the more detailed engineering studies to determine the "threshold" costs of such changes. They had been soliciting data from PRB coal suppliers since at least 1998, and had bids beginning in 2001. In 2003 and beyond, such bids were being evaluated and compared with CAPP and imported coal options. These are the types of actions I would expect to see by a company seriously considering fuel switching.

V. MARKET EVALUATION OF PRB COAL AND COALS PURCHASED AND BURNED AT CR4 AND CR5 1996-2005

Q. Did you analyze how introducing a blend of PRB coal to Crystal River units 4 and 5 during the 1996-2005 time period would have affected the evaluated coal costs to the unit?

A. Yes. I developed a model which calculated what the delivered and evaluated price of PRB coal to Crystal River would have been for each year from 1996-2005 assuming that PEF had made such purchases. I also analyzed the actual deliveries of waterborne coals to CR4 and CR5 during this period to determine which coals would have been displaced by the PRB shipments.

Q. What analysis did you conduct of actual deliveries?

A. I reviewed the FERC Form 423 data for Crystal River coal deliveries including shipments for each year from 1996-2005. This provided information about the coal quantities, sources, quality parameters, and prices for the various shipments. I further parsed the data to focus on waterborne deliveries of coal since PRB coal would have displaced other waterborne coals. I found that 97% of the coal delivered by water during this period was compliance coal, therefore, I could ignore the impact on waterborne coals for CR1 and CR2 since these were relatively small. In fact, PEF documents note the difficulty of acquiring compliance coals for rail delivery to the plant.

Q. Did you consider the effect of existing contracts?

A. Yes. I reviewed information provided by PEF about coal contracts, contract expiration dates, and whether the coal was delivered by rail or water. In 1996, PEF had term contracts in place for compliance coals. The most significant contracts for waterborne transport included Massey (1982-2002), and Pen (1995-1998). Contracts like the PMJV contract were significant too but were all-rail deliveries. I treated these waterborne contract commitments as constraints in that PEF would have needed to terminate the existing agreements in order to replace these coal sources with PRB coal.

Q. How did you analyze PRB coal prices F.O.B. mine?

A. Information about Powder River Basin coal prices was obtained from various trade publications which provided information on a daily or weekly basis about the prices for PRB 8800 Btu 0.8lb. SO_2/MMBtu coals. I also reviewed the results of the PEF bid solicitations to see how those compared with market prices. My assumption was that a PEF agreement would be re-priced annually, but that there would be a time lag of 6-12 months between when the bids would be solicited and the coals delivered. Prices were held constant at the average price for the following twelve months. In my experience, companies that use PRB coals will do both term and spot solicitations and generally conduct the term solicitations many months ahead of actual deliveries. Tampa Electric Company's ("TECO's") FERC Form 423 data indicate that they purchased PRB coals largely on a spot basis. My approach of calculating prices annually for this comparison would have been similar to purchasing coal on a spot basis.

Q. How did you analyze the rail transportation rate to move coal from the PRB to the river?

A. I assumed that PEF would have negotiated a term rail contract for PRB deliveries to a dock along the Mississippi River. This is a similar route to the one that TECO used for its PRB deliveries. Platts CoalDat estimates the 1996 TECO rail rate at $13.96/ton to Cook Coal Terminal. This would translate into 10.9 mills per ton-mile (this is one tenth of a cent per ton per mile) for the movement. Assuming the coal was shipped to St. Louis, the rail rate would be about $12.83 per ton assuming the same mill rate. This approximates the $14.00/ton rate to the Cora dock (including dumping fees) used in the PEF 1997 analysis (Exhibit No. (JNH-4)).

In February 2000, PEF received a bid of $11.20 in Union Pacific (UP) cars from the PRB to Cora Dock. (See PEF-FUEL-004728-30). This is about 10 mills per ton-mile (this is one tenth of a cent per ton per mile) for the 1,124 mile movement. Because western rail rates for new movements were relatively constant between 2000 and 2004, I have used the same rail rate each year.

In 2005, I increased the rail rate by 2 mills per ton-mile to account for the market increase in rail rates (this is supported by an EPRI survey conducted for 2005) and added 15% for the BNSF fuel surcharge. This increased the rate from $11.20/ton to $15.51/ton (13.8 mills/ton-mile) in 2005.

Consistent with my treatment of the coal prices and the capital costs, each year I would determine what the costs would be for PEF to enter into a new agreement for coal transportation.

Q. How did you analyze the cost of the rail equipment to move the coal to the river?

A. I used the rail rate in UP supplied equipment offered in the February 2000 bid. The difference between the bid in railroad and shipper supplied equipment was $2.10/ton.

Q. How did you analyze the barge transfer cost?

A. Information with regard to river dock transfer from rail-to-barge was set based on the rates used at the PEF owned Kenova River Terminals (KRT) which is also a rail-to-barge terminal. This was approximately $.75/ton in 1996 and had increased to about $1.10 by 2005.

Q. What did you use for the barge rate?

A. The barge portion of the movement was based upon the regulator for waterborne coals which governed the PEF transportation rates during this period. By "regulator," I mean the waterborne market proxy rate established by the Commission. The regulator used a 1996 rate for barging central Appalachian coals from the Huntington, West Virginia area to New Orleans of $7.83/ton. This rate was adjusted based on published information about the rates for barge shipments for coal between Huntington, West Virginia and Davant, Louisiana and between St. Louis and Davant, Louisiana during 1993-1995, the three year period preceding the presumed commitment to PRB coal. During this period, the rates from St. Louis were 83% of the Big Sandy rates. Thus the $7.83/ton rate under the regulator would have been adjusted to $6.50/ton for 1996. The base rate was then adjusted based on the change in the regulator.

In an analysis entitled "Estimated Powder River Basin Origin Transportation Market" prepared in a 1997 PEF document (Exhibit No. __ (JNH-4)), a barge rate is estimated using the pricing under the regulator but adjusting the rate based on the relative distances to the Gulf transfer facility from the CAPP and PRB origin docks. Using that methodology would produce a rate of $5.57/ton, but I believe that this understates the rate from St. Louis. First, barge rates always have some fixed component and so they do not vary by distance alone. Second, the market rates are indicative of economic forces that include many factors other than distance (e.g. tow size, traffic patterns). While the PEF approach may have been more favorable towards PRB coal, I do not think it was more accurate.

Q. How did you calculate the rate for the transfer at IMT?

A. The IMT transloading charges were taken directly from the transportation regulator. However, using the regulator for IMT transloading charges assumes that IMT was capable of handling PRB coals without additional capital and O&M costs plus the additional time necessary to provide the service. This does not appear to be the case given the greater costs the terminal likely would have incurred for handling PRB coals.

Q. Why did you not blend the coals at IMT?

A. This is possible if IMT was capable of handling and blending PRB coals, but if the object was to maximize deliveries of PRB coal to the plant because it was supposed to be less expensive than CAPP coals, blending at IMT would have consumed scarce cross-Gulf transport capacity. Assuming that PRB and CAPP coals were blended at IMT, and given that the reasonable, maximum capacity for waterborne delivery is 2.4 MMtpy, then only a blend of coals using 1.2 MMtpy of PRB coal could be delivered to the plant.

Q. How did you calculate the rate for the cross-Gulf movement?

A. These rates were taken directly from the transportation regulator.

Q. How did you calculate a charge for blending at the plant?

A. The adjustment made for changes in capital and operating costs at the plant to accommodate PRB coals include the costs of building and operating the coal blending facilities. These estimates were provided by PEF and its experts. See Exhibit No. ___ (JNH-5).

Q. What other adjustment did you make to the PRB delivered prices?

A. As I indicated previously, to properly compare the PRB coals with the other coals it is important to do this on an "evaluated" basis using the CQIM results. Based upon information contained in the bid evaluations for the available years 1998, 2001, and 2003-2006, and the PEF interrogatory response (response to OPC's

First Set of Interrogatories No. 16), I have adjusted the PRB delivered prices to an "evaluated basis" for comparison with the CAPP coals.

The differences varied during this period depending partly upon high SO_2 prices that reduce the PRB penalty as would be expected since the PRB coal is lower in sulfur than the other coals.

Q. What were the results of your PRB delivered and evaluated price analysis?

A. Exhibit No. __ (JNH-6) shows the results of this analysis on a delivered price and an evaluated price basis. The evaluated price basis is the proper one for comparison with CAPP and imported coals.

Q. How did you determine the amount of PRB coal that would be blended at the plant?

A. For each year from 1996-2005, I determined the actual deliveries of coal from each source and the delivered price of that coal. I compared the delivered prices of all coals not under long term contract in each year with the evaluated cost of the PRB coal. PRB was allowed to displace the most expensive non-PRB coals first and continue such displacement until the maximum coal blend of 40% of the Btu's had been reached. The maximum blend percentage for PRB coal was assumed to be 10 percent of the total Btu's used at CR4 and CR5 during 1996 (the first year of PRB coal use under Mr. Sansom's analysis), and up to 40 percent of the total Btu's thereafter. However, during 1997-2001 the maximum blend ratio for PRB coal was adjusted downward to take into account long-term contracts for waterborne CAPP coal that had been entered into with Massey and Pen prior to 1996. To the extent that the PRB coal displaced higher cost non-PRB coals then PEF would have lower costs. To the extent that PRB coal would have displaced lower priced non-PRB coals, PEF would have experienced higher costs. All of this analysis is without regard to the impact on unit output which is not reflected in the "evaluated" analysis.

Q. How did you treat the capital costs associated with a conversion to PRB coal?

A. The analysis of Mr. Hatt shows that capital cost would have ranged from a low of $48.6M to a high of $73.7M. The operating costs were $2.01M/year. The combined operating and capital costs would have required that any PRB coal savings be sufficient to offset a $9.92M annual cost associated with the facilities and added operating costs of blending PRB coal at the plant. Each year I include this capital in the threshold calculation as part of the PRB coal cost analysis in my comparison.

Q. What do the results show?

A. The results in Exhibit No. __ (JNH-7) show that from 1996 to 2003, converting to PRB coal would actually have been more expensive for PEF than continuing to rely upon its other coal sources. In 2001, the data indicate that PEF would have experienced savings by switching to PRB coal, but in fact this is not what PEF found. The 2001 solicitation happened to occur at a point in the market when PRB coal prices had peaked. PEF got only three 8800 BTU PRB responses from two bidders for different contract durations. The coal price quoted for an 8800 BTU coal was between $11.30/ton and $15.50/ton. The average spot price for 2001 used in our model was $4.66/ton. Had PEF accepted the bid offered, the cost of PRB would have exceeded the cost of their other alternatives.

In the 2003 RFP responses, import coals ranked lower than PRB coals on an evaluated cost basis. The Company, nevertheless, subsequently commenced its investigation of PRB coals.

In 2004 and 2005 with higher SO_2 prices and substantial increases in CAPP and import coals, PRB coal would have provided a savings simply on an evaluated price basis. Accounting for the actual "threshold" capital and operation and maintenance costs, or the impacts of de-rates from a fuel switch, could have made this option appear uneconomical. In addition, the PRB capital costs analysis assumes a 30-year recovery life for the $60M average capital investment. If these costs were to be recovered before PEF installs scrubbers in about five years, the capital cost recovery would need to occur about five times as fast. This will tend to discourage a switch to PRB coal even now.

Q. By 2003 to 2005 was PEF focusing on PRB coal?

A. Yes. It was preparing to conduct test burns and evaluating whether a coal switch was appropriate.

Q. Did your analysis consider the reliability of western coal transportation?

A. Yes. In the summer of 2005, derailments of PRB coal trains disrupted rail deliveries and lead to an intensive effort by the rail carriers to repair track and ballast related problems in the PRB. This repair effort disrupted rail shipments for many months. On average, utilities received only 92.5% of planned deliveries during this period. Based on this experience, I assumed that only 92.5% of the planned PRB deliveries would have been received by PEF in 2005.

Q. Are there any other issues related to such a switch?

A. Yes. As I mentioned, one of the most significant concerns that utilities have with regard to switching from a bituminous to a sub-bituminous coal is its impact on unit output called a "derate". These can be very expensive because loss of generating capacity at a base load unit usually means that power must be purchased or new generation built. Both of these can be very costly. It is my understanding that CR4 and CR5 operate at above their design capacity in terms of unit output. If one reason for this is because they operate on a higher Btu content of coal than they were designed for, and substituting PRB coal for bituminous coal will diminish unit output, then this cost needs to be included in the analysis. I have not done that.

I have, however, included as Exhibit No. ___ (JNH-8) a chart summarizing the higher costs to customers had PEF burned an equal blend of PRB and bituminous coals at CR4 and CR5 from 1996 to 2005, as OPC alleges PEF should have done, together with the SO_2 allowances and de-rate valuations that have been calculated by other PEF witnesses. The SO_2 allowances are addressed by Mr. Dean and the de-rate valuation is addressed by Mr. Crisp.

My understanding is that PEF has also announced plans to install scrubbers at Crystal River. To the extent that capital would be spent to install FGD and the units would be fired using cheaper high sulfur coal, then the time available to recover any capital spent on a PRB switch would need to be recovered during the period prior to the scrubber switch. I do not know how this would affect the economics of using PRB coal at Crystal River but it certainly is a factor that must be taken into account in any decision contemplating a switch to a PRB blend.

In addition, mercury regulations under CAMR (Clean Air Mercury Rule) may make it difficult to burn PRB coal at the Crystal River units. These state rules are still under development, but in some states these regulations may discourage the use of PRB coals because the form of mercury contained in those coals is difficult to remove. I also have not considered this impact in my analysis but, again, it is a factor that must be considered in contemplating a fuel switch to a PRB blend.

VI. REVIEW OF MR. SANSOM'S TESTIMONY AND DAMAGES ASSESSMENT

Q. Have you reviewed the testimony of Mr. Sansom and do you have any comments?

A. Yes. Mr. Sansom's analysis and damages assessment is flawed in a number of areas. I will discuss my observations in regard to his Exhibit RS-27, "Fuel Damages Summary."

Q. What does Mr. Sansom use as the basis of his PRB coal costs?

A. He relies upon the prices that TECO paid for PRB coals delivered to New Orleans for Gannon as the basis of his analysis through 2002. He provides no background on the circumstances under which those purchases were made and how they compare with market. While TECO's contract price may be indicative of market at the time it was signed, it would seem more appropriate to examine market data at the time that PEF would reasonably have entered into a new PRB contract. Moreover when TECO stops receiving PRB coal, he relies on changes in delivered prices to various rail-served PRB plants which are not analogous to the Crystal River units.

Q. How does he calculate the transportation costs?

A. Mr. Sansom improperly fails to account for the transportation rates that PEF would actually have used to evaluate the PRB coal option and that would have been passed through to customers. Under the FPSC approved agreement, PEF would have used the market proxy to establish rates for portions of the transportation system. Clearly the actual rates approved under the regulator for transloading and storage at IMT and cross-Gulf movement by Dixie Fuels would be applicable. While the market proxy includes a barge rate component, that component applies from Central Appalachia. However, there is precedent in applying a portion of the regulator for import coals. Under FPSC orders, PEF was able to adjust the waterborne regulator to allow for import coal. This approach allowed PEF to use a percentage of the waterborne regulator cost for the recovery of charges associated with import coals, since those coals did not use the portion of the waterborne route upstream of New Orleans. By not basing the analysis on the regulator components, Mr. Sansom's analysis deviates from the reality of what PEF would have encountered. This has the effect of understating the PRB delivered costs in column 6 of his chart.

In addition for 2003, Mr. Sansom uses the changes in the delivered prices to plants Miller and Scherer. How these compare to the Crystal River situation is questionable. Miller is a BNSF direct rail served facility which takes over 10 MMtpy of PRB coal. Plant Scherer is also rail served and takes over 13 MMtpy of PRB coal. It is not obvious why either of these plants and their delivery systems are reliable analogs for Crystal River.

Q. How does Mr. Sansom handle the constraints of existing contracts?

A. He ignores them. PEF had contracts with Massey and Pen Coal which required the company to purchase CAPP coal for water delivery. To take PRB coal shipments by water in amounts that are in excess of these minimum contractual commitments would have required buying out of the contracts or breaching them. Mr. Sansom did not account for this constraint. By failing to account for these contracts, Mr. Sansom's analysis is in error, but the effects vary from year-to-year. In the early years, when these contracts cannot be displaced, the effect is to reduce the purported savings from PRB coals (or cause them to go negative) since the displaced coals are less costly then the contract coals. In later years depending upon the relationship between current market prices and existing contract prices, the economic impact of this constraint will vary.

Q. How does Mr. Sansom address delivery constraints?

A. Mr. Sansom ignored the limitations on rail and barge deliveries to the plant site. Restrictions on water movements to the site would have made it impossible to deliver the quantities of PRB coal that he forecast in column 4 of his chart and meet the other tonnage obligations under existing contracts. This effect occurs in most of the years and has the effect of reducing the amount of PRB coal that can be transported to the plant. The impact of reducing PRB deliveries on his purported damages varies by year. In those years where the PRB coal is not cheaper than the alternatives, further restricting its use has no impact. In 2003 to 2005, it can have a more significant impact.

Q. How does he adjust for the utilization penalty associated with PRB coals?

A. Mr. Sansom does not provide for any utilization adjustment associated with changing to the lower Btu, higher moisture PRB coals. PEF makes utilization adjustments based on coal quality parameters which it uses to adjust coals to match the specification coal. While the as-burned adjustment will vary by the exact coal, Mr. Sansom fails to account for this effect in his analysis. It would have the effect of penalizing the PRB coals between about $.03-.15/MMBtu. The overall effect of his failure to apply the utilization penalty is to overstate his purported damages by about $15M.

Q. What about the impact on unit output?

A. Mr. Sansom also ignores the impact on generating unit output given the use of a PRB blend. As discussed in the testimony of others, CR4 and CR5 each generates power at more than its design capacity. Switching to PRB coal, while not technically de-rating the unit below its original design capacity, would reduce generation below current output levels. This reduction in power would need to be replaced with more expensive purchased power or added generation units. This calculation is performed in the testimony of another PEF witness.

Q. **How does Mr. Sansom account for the capital investments that would be required for a PRB switch?**

A. Mr. Sansom ignores the capital investments required to burn PRB coal. The PEF analysis of PRB use specifies various investments and operations modifications required to facilitate PRB use. These range from dust control measures to transportation infrastructure. These also become the threshold items for making a fuel switching decision. These investments must be repaid through fuel cost savings and Mr. Sansom does not analyze these capital costs or whether the fuel savings are sufficient to repay them. These capital investments total between $48.6M and $73.7M. PEF would need to forecast savings sufficient to offset these investments in order to make the PRB conversion. It is only in 2004 and 2005 that savings become apparent that would support investments of this magnitude. Whether even these savings levels would support the capital investment would likely depend upon the number of years that the units would continue to burn PRB coal before scrubbing. After scrubbers are installed, PEF may have cheaper coal supplies available.

Q. To what does Mr. Sansom compare the PRB coal costs?

A. He compares the spot PRB prices available to TECO to the average spot and contract CAPP prices of coal for PEF, which is fundamentally wrong. PRB coals would have competed each year with those coals which were up for renewal, not the coals already under contract. Especially in the early years of his analysis, he is comparing the PRB coals with more expensive CAPP contract coals, which is inappropriate since PEF could not breach those contracts.

Q. Do you have any other criticisms?

A. Yes. Mr. Sansom ramps up PRB deliveries to the full 50% of blend within two years. In my experience many plants that are switching to PRB coal take a longer time to make the change.

Mr. Sansom also says he is accounting for the risks associated with PRB rail delivery in 2005 by providing for a 7.5% reduction in PRB deliveries in that year. I agree that a 7.5% reduction in PRB deliveries is appropriate for 2005 due to the risks associated with rail deliveries that year and I have made that adjustment in my analysis. However, I cannot tell that Mr. Sansom has actually made this adjustment in his damages calculation.

VII. CONCLUSION

Q. What are your conclusions?

A. Having conducted my own analysis of switching CR4 and CR5 to a PRB coal blend, and having reviewed the analysis of Mr. Sansom, I conclude the following:

- Between 1996 and 2003, the differential between CAPP and PRB coals did not support a switch to PRB coal. Had PEF switched costs would have been higher.
- In 2004 - 2005, it appears that the evaluated price of PRB to Crystal River would have been less than the delivered price of CAPP and imported coals. During this period PEF investigated the use of PRB coals.
- Whether it was appropriate for PEF to burn PRB coals would depend upon additional capital requirements; the impact of the PRB coals on unit availability and output (MW capable of being generated); the status of plans to install scrubbers at the site; and any other perceived penalties or risks, such as the CAMR impact on a PRB blend. Even in 2004-2005, it may be difficult to justify a PRB switch if the Company is planning to switch to PRB coals within the next five years when the Company is also planning to scrub the units.

- The western coal transportation disruptions in 2005 and the loss of deliverability coupled with a major PRB price increase would likely have affected PEF's thinking about the value of a PRB switch after 2005.
- Mr. Sansom's analysis is badly flawed and cannot be used as the basis for a calculation of damages.

Q. Does this conclude your testimony?

A. Yes.

Development of the Coal Quality Expert™

Project completed

Participants

ABB Combustion Engineering, Inc. and CQ Inc.

Additional Team Members

Black & Veatch—cofunder and software developer

Electric Power Research Institute—cofunder

The Babcock & Wilcox Company—cofunder and pilot-scale tester

Electric Power Technologies, Inc.—field tester

University of North Dakota, Energy and Environmental Research Center—bench-scale tester

Utility Companies—(5 hosts)

Locations

Grand Forks, Grand Forks County, ND (bench tests)

Windsor, Hartford County, CT (bench- and pilot-scale tests)

Alliance, Columbiana County, OH (pilot-scale tests)

Five utility host sites

Technology

CQ Inc.'s EPRI Coal Quality Expert™ (CQE™) computer software

Plant Capacity/Production

Full-scale testing took place at utility sites ranging in size from 250–880 MWe.

Coal

Wide variety of coals and blends

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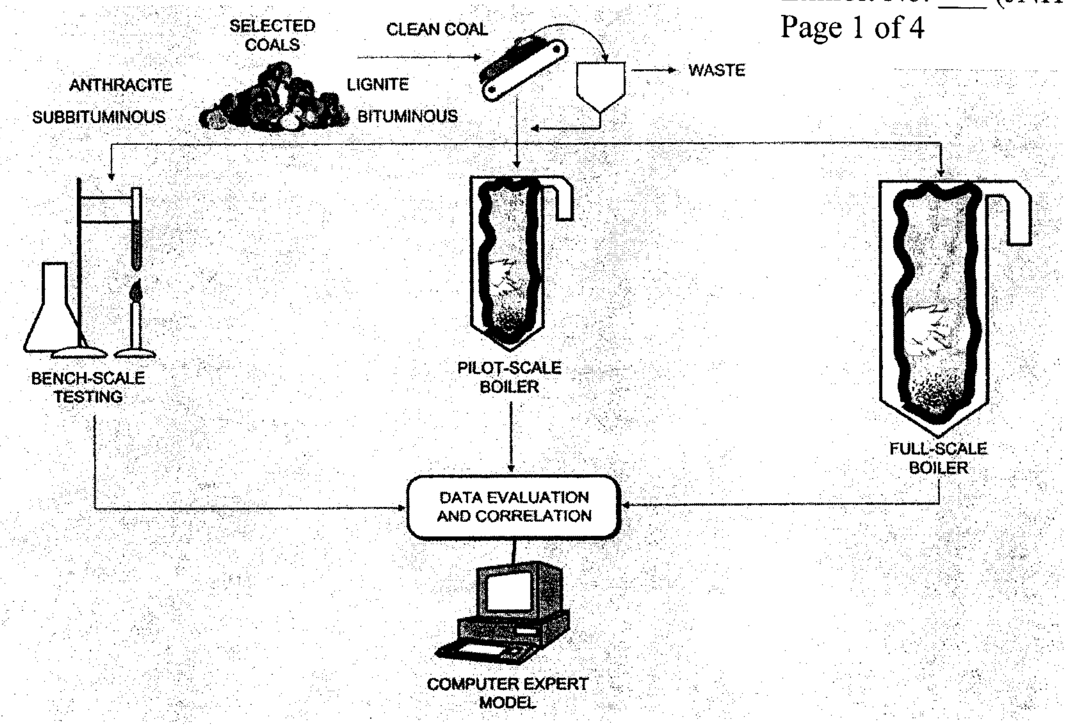
Pentium is a registered trademark of Intel.
OS/2 Warp is a registered trademark of IBM.
Windows is a registered trademark of Microsoft Corporation.



Project Funding

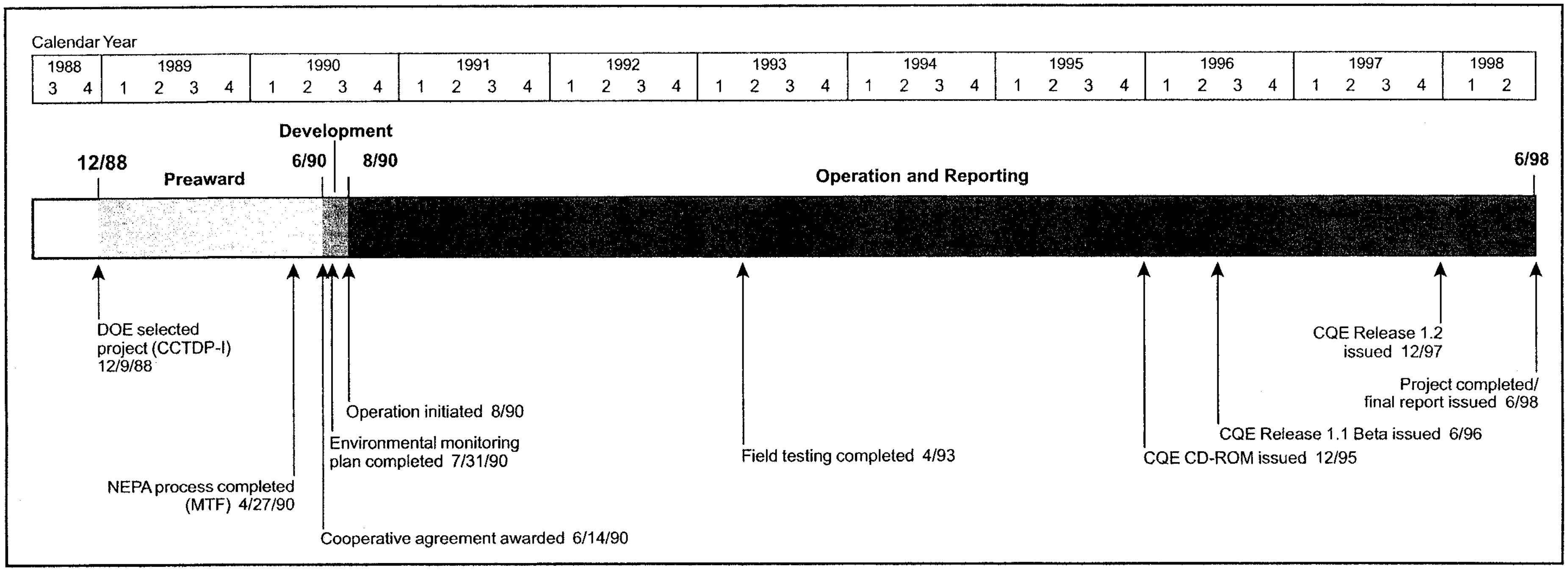
Total	$21,746,004	100%
DOE	10,863,911	50
Participants	10,882,093	50

Project Objective

The objective of the project was to provide the utility industry with a PC software program it could use to confidently and inexpensively evaluate the potential for coal-cleaning, blending, and switching options to reduce emissions while producing the lowest cost electricity. Specifically the project was to: (1) enhance the existing Coal Quality Information System (CQIS™) database and Coal Quality Impact Model (CQIM™) to allow assessment of the effects of coal-cleaning on specific boiler costs and performance; and (2) develop and validate CQE™, a model that allows accurate and detailed prediction of coal quality impacts on total power plant operating cost and performance.

Technology/Project Description

The CQE™ is a software tool that brings a new level of sophistication to fueling decisions by integrating the system-wide impact of fuel purchase decisions on coal-fired power plant performance, emissions, and power generation costs. The impacts of coal quality; capital improvements; operational changes; and environmental compliance alternatives on power plant emissions, performance, and production costs can be evaluated using CQE™. CQE™ can be used to systematically evaluate all such impacts, or it may be used in modules with some default data to perform more strategic or comparative studies.



Results Summary

Environmental

- CQE™ includes models to evaluate emission and regulatory issues.

Operational

- CQE™ can be used on a stand-alone computer or as a network application for utilities, coal producers, and equipment manufacturers to perform detailed coal impact analyses.
- Four features included in the CQE™ program are:
  - Fuel Evaluator,
  - Plant Engineer,
  - Environmental Planner, and
  - Coal-Cleaning Expert.
- CQE™ can be used to evaluate:
  - Coal quality,
  - Transportation system options,
  - Performance issues, and
  - Alternative emissions control strategies.
- CQE™ operates on an OS/2 Warp® (Version 3 or later) operating system with preferred hardware requirements of a Pentium®-equipped personal computer, 1 gigabyte hard disk space, 32 megabytes RAM, 1024x768 SVGA, and CD-ROM.

Economic

- CQE™ includes economic models to determine production cost components for coal-cleaning processes, power production equipment, and emissions control systems.

Project Summary

CQE™ began with EPRI's CQIM™, developed for EPRI by Black & Veatch and introduced in 1989. CQIM™ was endowed with a variety of capabilities, including evaluating Clean Air Act compliance strategies, evaluating bids on coal contracts, conducting test-burn planning and analysis, and providing technical and economic analyses of plant operating strategies. CQE™, which combines CQIM™ with other existing software and databases, extends the art of model-based fuel evaluation established by CQIM™ in three dimensions: (1) new flexibility and application, (2) advanced technical models and performance correlations, and (3) advanced user interface and network awareness.

Operational Performance

Algorithm Development. Data derived from bench-, pilot-, and full-scale testing were used to develop the CQE™ algorithms. Bench-scale testing was performed at ABB Combustion Engineering's facilities in Windsor, Connecticut and the University of North Dakota's Energy and Environmental Research Center in Grand Forks, North Dakota. Pilot-scale testing was performed at ABB Combustion Engineering's facilities in Windsor, Connecticut and Alliance, Ohio. The five field test sites were:

- Alabama Power's Gatson, Unit No. 5 (880 MWe), Wilsonville, Alabama;
- Mississippi Power's Watson, Unit No. 4 (250 MWe), Gulfport, Mississippi;
- New England Power's Brayton Point, Unit No. 2 (285 MWe) and Unit No. 3 (615 MWe), Somerset, Massachusetts;
- Northern States Power's King Station (560 MWe), Bayport, Minnesota; and
- Public Service Company of Oklahoma's Northeastern, Unit No. 4 (445 MWe), Oologah, Oklahoma.

The six large-scale field tests consisted of burning a baseline coal and an alternate coal over a two-month period. The baseline coal was used to characterize the operating performance of the boiler. The alternate coal, a blended or cleaned coal of improved quality, was burned in the boiler for the remaining test period.

The baseline and alternate coals for each test site also were burned in bench- and pilot-scale facilities under similar conditions. The alternate coal was cleaned at CQ Inc. to determine what quality levels of clean coal can be produced economically and then transported to the bench- and pilot-scale facilities for testing. All data from bench-, pilot-, and full-scale facilities were evaluated and correlated to formulate algorithms used to develop the model.

CQE™ Capability. The OS/2®-based program evaluates coal quality, transportation system options, performance issues, and alternative emissions control strategies for utility power plants. CQE™ is composed of technical tools to evaluate performance issues, environmental models to evaluate emissions and regulatory issues, and economic models to determine production cost components. These include consumables (*e.g.*, fuel, scrubber additives), waste disposal, operation and maintenance, replacement energy costs, and operation and maintenance costs for coal-cleaning processes, power production equipment, and emissions control systems. CQE™ has four main features:

- Fuel Evaluator—Performs system-, plant-, or unit-level fuel quality, economic, and technical assessments.
- Plant Engineer—Provides in-depth performance evaluations with a more focused scope than provided in the Fuel Evaluator.
- Environmental Planner—Provides access to evaluation and presentation capabilities of the Acid Rain Advisor.
- Coal-Cleaning Expert—Establishes the feasibility of cleaning a coal, determines cleaning processes, and predicts associated costs.

Software Description. The CQE™ includes more than 100 algorithms based on the data generated in the six full-scale field tests. The CQE™ design philosophy underscores the importance of flexibility by modeling all important power plant equipment and systems and their performance in real-world situations. This level of sophistication allows new applications to be added by assembling a model of how objects interact. Updated information records can be readily shared among all affected users because CQE™ is network-aware, enabling users throughout an organization to share data and results. The CQE™ object-oriented design, coupled with an object database management system, allows different views of the same data. As a result, staff efficiency is enhanced when decisions are made.

CQE™ also can be expanded without major revisions to the system. Object-oriented programming allows new objects to be added and old objects to be deleted or enhanced easily. For example, if modeling advancements are made with respect to predicting boiler ash deposition (*i.e.*, slagging and fouling), the internal calculations of the object that provides these predictions can be replaced or augmented. Other objects affected by ash deposition (*e.g.*, ash collection and disposal systems, sootblower systems) do not need to be altered; thus, the integrity of the underlying system is maintained.

System Requirements. CQE™ uses the OS/2® operating system. CQE™ can operate in stand-alone mode on a single computer or on a network. Technical support is available from Black & Veatch for licensed users.

Commercial Applications

The CQE™ system is applicable to all electric power generation plants and large industrial/institutional boilers that burn pulverized coal. Potential users include fuel suppliers, environmental organizations, government and regulatory institutions, and engineering firms. International markets for CQE™ are being explored by both CQ Inc. and Black & Veatch.

EPRI owns the software and distributes CQE™ to EPRI members for their use. CQE™ is available to others in the form of three types of licenses: user, consultant, and commercializer. CQ Inc. and Black & Veatch have each signed commercialization agreements, which give both companies non-exclusive worldwide rights to sell user's licenses and to offer consulting services that include the use of CQE™ software.

CQE™ was recognized in 1996 by the Secretary of Energy and the President of EPRI as the best of nine DOE/EPRI cost-shared utility research and development projects under the "Sustainable Electric Partnership" program.

Docket No. 060658
Progress Energy Florida
Exhibit No. ___ (JNH-1)

The CQE™ program has been incorporated in the Vista program package, which is the latest version of the software. Vista operates in the Windows® environment. The Vista Fuels Web server has a Home Page on the World Wide Web (http://www.fuels.bv.com) to promote the software, facilitate communications between developers and users, and eventually allow software updates to be distributed over the Internet. The Home Page also helps attract the interest of international utilities and consulting firms.

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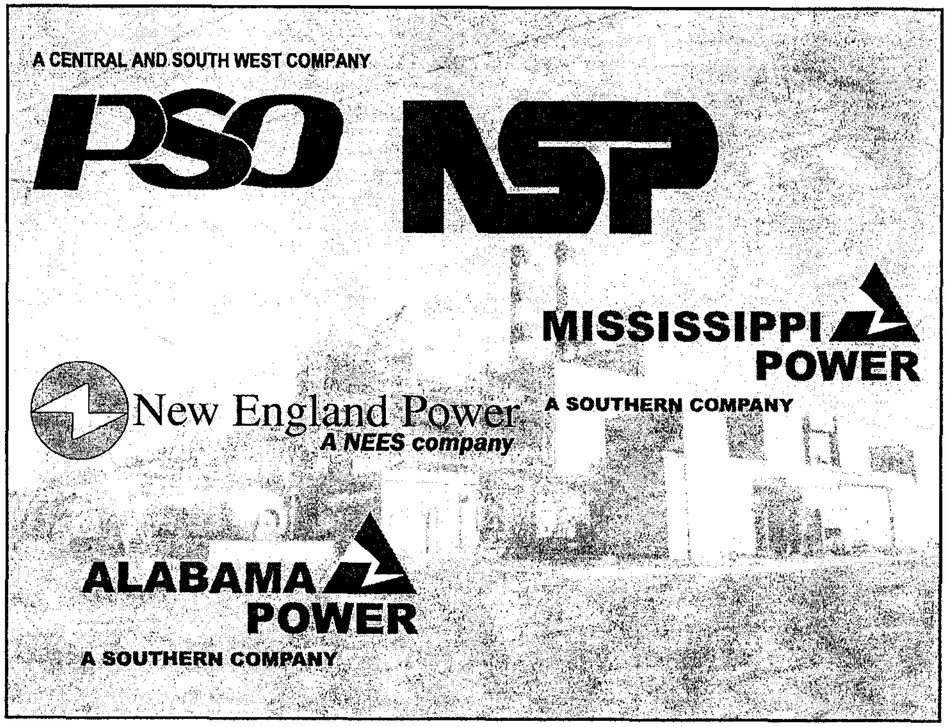
References

Final Report: Development of a Coal Quality Expert. CQ Inc. June 20, 1998.

"Recent Experience with the CQE™." Harrison, Clark D. *et al. Fifth Annual Clean Coal Technology Conference: Technical Papers.* January 1997.

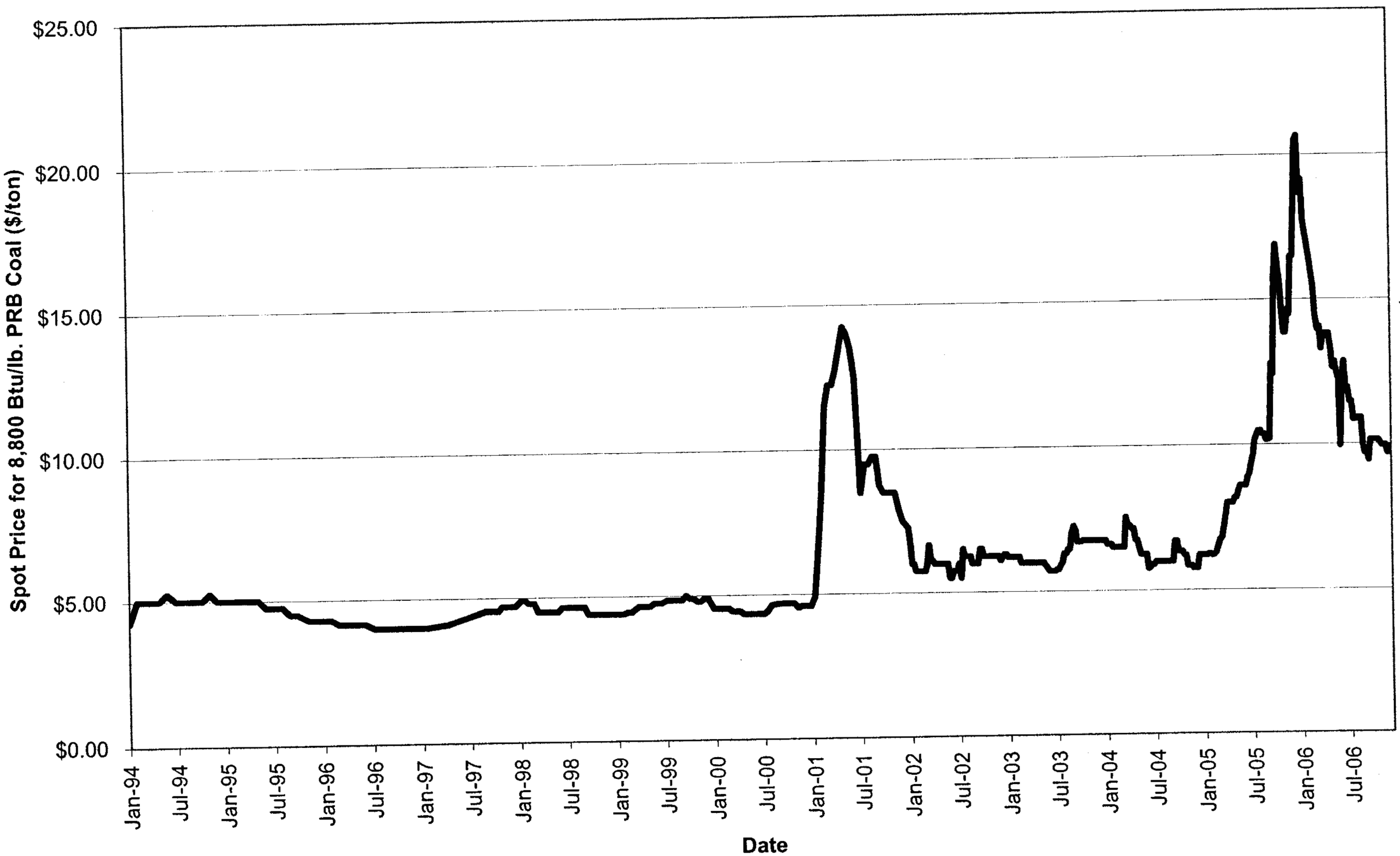
Comprehensive Report to Congress on the Clean Coal Technology Program: Development of the Coal Quality Expert. ABB Combustion Engineering, Inc., and CQ Inc. Report No. DOE/FE-0174P. U.S. Department of Energy. May 1990. (Available from NTIS as DE90010381.)



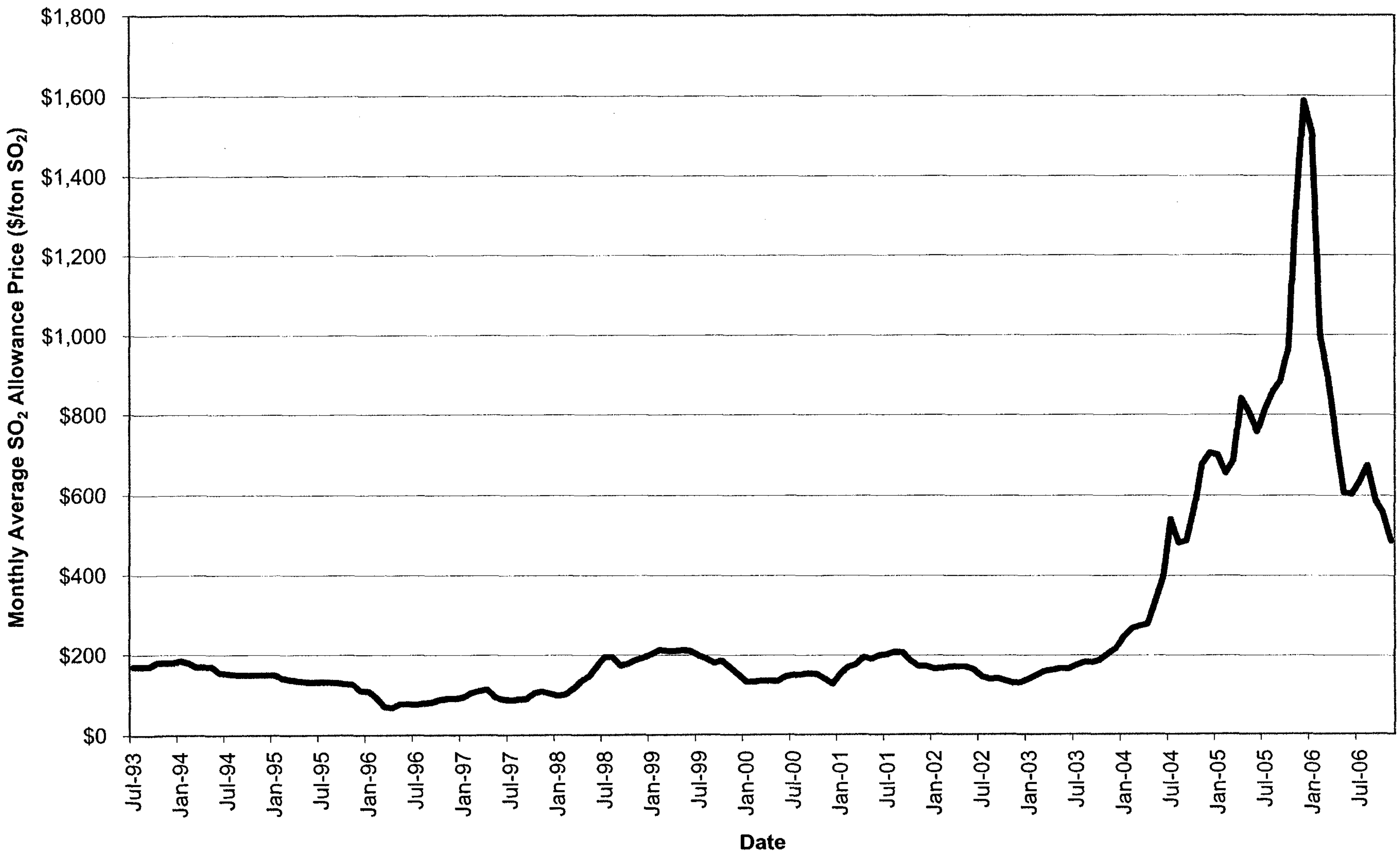
Five utilities acted as hosts for field tests of CQE™.

Docket No. 060658
Progress Energy Florida
Exhibit No. ___ (JNH-2)
Page 1 of 1

PRB Coal Prices 1994-2006



SO_2 Allowance Prices, July 2003 - November 2006



ESTIMATED POWDER RIVER BASIN ORIGIN TRANSPORTATION "MARKET"

Estimated Mine to Cora Dock & Transfer	$14.00
Estimated Cora to IMT River Move[1]	5.57
Estimated IMT & Gulf	12.70
	$32.27

[1]Base "River" Cost	$7.32
1997 "River" Market	$8.30
Increase	13.4%

Cora Dock to IMT Mileage	995
Ceredo Dock to IMT Mileage	1564
Ceredo Rate to IMT (1992)	$7.71
Implied Cora Rate (1992)	$4.91

Implied 1997 Cora Rate X 1.134 Escalation	$5.57

PEF cost to run and operate two pulverizers, one at CR4 and one at CR5
($ millions)

Docket No. 060658
Progress Energy Florida
Exhibit No. ____ (JNH-5)

	LOW CASE						HIGH CASE					
	Low Cost	Annual Return* 11.45%	Retail Method Deprec Rate**	Deprec Exp	Total Annual Sytem Cost	Annual Retail Cost 95%	High Cost	Annual Return* 11.45%	Retail Method Deprec Rate**	Deprec Exp	Total Annual Sytem Cost	Annual Retail Cost 95%
Capital Additions/Modifications:												
1. Wash-down system	$2.00	$0.23	3.50%	$0.07	$0.30	$0.29	$2.00	$0.23	3.50%	$0.07	$0.30	$0.29
2. Silo modifications	1.00	0.11	3.50%	0.04	0.15	0.14	3.00	0.34	3.50%	0.11	0.45	0.43
3. Dust collection systems	6.00	0.69	3.50%	0.21	0.90	0.86	7.00	0.80	3.50%	0.25	1.05	1.00
4. Fire protection systems	1.00	0.11	3.50%	0.04	0.15	0.14	2.00	0.23	3.50%	0.07	0.30	0.29
5. Reclaim hopper system	15.00	1.72	3.50%	0.53	2.25	2.14	20.00	2.29	3.50%	0.70	2.99	2.84
6. Additional pulverizers	4.00	0.46	3.50%	0.14	0.60	0.57	10.00	1.14	3.50%	0.35	1.49	1.42
7. Boiler modifications	5.00	0.57	3.50%	0.18	0.75	0.71	10.00	1.14	3.50%	0.35	1.49	1.42
8. Water cannons/sootblowers	2.00	0.23	3.50%	0.07	0.30	0.29	5.00	0.57	3.50%	0.18	0.75	0.71
9. Upgrades to conveyor belts	8.00	0.92	3.50%	0.28	1.20	1.14	10.00	1.14	3.50%	0.35	1.49	1.42
10. Online computer analyzer program to oversee blending	0.20	0.02	3.50%	0.01	0.03	0.03	0.30	0.03	3.50%	0.01	0.04	0.04
11. D-10 Bulldozers	1.00	0.11	3.50%	0.04	0.15	0.14	1.00	0.11	3.50%	0.04	0.15	0.14
12. Front Loader	1.00	0.11	3.50%	0.04	0.15	0.14	1.00	0.11	3.50%	0.04	0.15	0.14
13. Upgrades to electrostatic precipitator	2.40	0.27	3.50%	0.08	0.35	0.33	2.40	0.27	3.50%	0.08	0.35	0.33
Total Capital Cost	48.60	5.55		1.73	7.28	6.92	73.70	8.40		2.60	11.00	10.47

*Return is based on 2002 Rate Case
**Deprec rate is based on approx 30 year life as reported in 2000 depreciation study

	Low Cost					Annual Retail Cost 95%	High Cost					Annual Retail Cost 95%
Ongoing O&M												
14. Dust suppression chemicals	1.00					0.95	1.00					0.95
15. Power consumption & maint on 2 add'l pulverizers	0.20					0.19	0.20					0.19
16. 1 add'l maintenance person to do fire watch and maintain belts	0.10					0.10	0.10					0.10
17. 2 add'l laborers to assist with wash down of coal dust	0.20					0.19	0.20					0.19
18. 2 add'l laborers to work on piles	0.20					0.19	0.20					0.19
19. Add'l water - 20,000 gallons/day	0.01					0.01	0.01					0.01
20. O&M on electrostatic precipitator	0.30					0.29	0.30					0.29
Total O&M Cost	2.01					1.92	2.01					1.92
Total Annual Retail Cost						$\boxed{\$8.84}$						$\boxed{\$12.39}$

EF cost to run and operate two pulverizers, one at CR4 and one at CR5
millions)

ERFECT RATEMAKING

		Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20	Yr 21	Yr 22	Yr 23	Yr 24	Yr 25	Yr 26	Yr 27	Yr 28	Yr 29	Yr 30
ow Case																															
1. Plant		$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60	$48.60
2. Accumulated Depreciation		0.85	2.55	4.25	5.95	7.65	9.36	11.06	12.76	14.46	16.16	17.86	19.56	21.26	22.96	24.66	26.37	28.07	29.77	31.47	33.17	34.87	36.57	38.27	39.97	41.67	43.38	45.08	46.78	48.09	48.55
3. Net Plant		47.75	46.05	44.35	42.65	40.95	39.24	37.54	35.84	34.14	32.44	30.74	29.04	27.34	25.64	23.94	22.23	20.53	18.83	17.13	15.43	13.73	12.03	10.33	8.63	6.93	5.22	3.52	1.82	0.51	0.05
4. Multiply by Rate of Return		11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%
5. Return on Net Plant		5.47	5.27	5.08	4.88	4.69	4.49	4.30	4.10	3.91	3.71	3.52	3.32	3.13	2.94	2.74	2.55	2.35	2.16	1.96	1.77	1.57	1.38	1.18	0.99	0.79	0.60	0.40	0.21	0.06	0.01
6.																															
7. Depreciation Expense	3.50%	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	0.92	
8. O&M Expense		2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01
9. Property Tax	1.5%	0.72	0.69	0.67	0.64	0.61	0.59	0.56	0.54	0.51	0.49	0.46	0.44	0.41	0.38	0.36	0.33	0.31	0.28	0.26	0.23	0.21	0.18	0.15	0.13	0.10	0.08	0.05	0.03	0.01	0.00
0. Total Expenses		4.43	4.40	4.38	4.35	4.33	4.30	4.27	4.25	4.22	4.20	4.17	4.15	4.12	4.10	4.07	4.04	4.02	3.99	3.97	3.94	3.92	3.89	3.87	3.84	3.81	3.79	3.76	3.74	2.94	2.01
1.																															
2. Total Revenue Require (line 5 + 11)		9.89	9.67	9.45	9.23	9.01	8.79	8.57	8.35	8.13	7.91	7.69	7.47	7.25	7.03	6.81	6.59	6.37	6.15	5.93	5.71	5.49	5.27	5.05	4.83	4.61	4.39	4.17	3.95	3.00	2.02
3. Retail % (approx.)		95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
4. Retail Revenue Requirements		$9.40	$9.19	$8.98	$8.77	$8.56	$8.35	$8.14	$7.93	$7.73	$7.52	$7.31	$7.10	$6.89	$6.68	$6.47	$6.26	$6.05	$5.84	$5.63	$5.42	$5.21	$5.01	$4.80	$4.59	$4.38	$4.17	$3.96	$3.75	$2.85	$1.92
igh Case																															
1. Plant		$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70	$73.70
2. Accumulated Depreciation		1.29	3.87	6.45	9.03	11.61	14.19	16.77	19.35	21.93	24.51	27.08	29.66	32.24	34.82	37.40	39.98	42.56	45.14	47.72	50.30	52.88	55.46	58.04	60.62	63.20	65.78	68.36	70.94	72.98	73.74
3. Net Plant		72.41	69.83	67.25	64.67	62.09	59.51	56.93	54.35	51.77	49.19	46.62	44.04	41.46	38.88	36.30	33.72	31.14	28.56	25.98	23.40	20.82	18.24	15.66	13.08	10.50	7.92	5.34	2.76	0.72	(0.04)
4. Multiply by Rate of Return		11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%	11.45%
5. Return on Net Plant		8.29	8.00	7.70	7.40	7.11	6.81	6.52	6.22	5.93	5.63	5.34	5.04	4.75	4.45	4.16	3.86	3.57	3.27	2.97	2.68	2.38	2.09	1.79	1.50	1.20	0.91	0.61	0.32	0.08	(0.00)
6.																															
7. Depreciation Expense	3.50%	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	1.51	
8. O&M Expense		2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01
9. Property Tax	1.5%	1.09	1.05	1.01	0.97	0.93	0.89	0.85	0.82	0.78	0.74	0.70	0.66	0.62	0.58	0.54	0.51	0.47	0.43	0.39	0.35	0.31	0.27	0.23	0.20	0.16	0.12	0.08	0.04	0.01	(0.00)
0. Total Expenses		5.68	5.64	5.60	5.56	5.52	5.48	5.44	5.40	5.37	5.33	5.29	5.25	5.21	5.17	5.13	5.10	5.06	5.02	4.98	4.94	4.90	4.86	4.82	4.79	4.75	4.71	4.67	4.63	3.53	2.01
1.																															
2. Total Revenue Require (line 5 + 11)		13.97	13.63	13.30	12.96	12.63	12.30	11.96	11.63	11.29	10.96	10.63	10.29	9.96	9.62	9.29	8.96	8.62	8.29	7.95	7.62	7.29	6.95	6.62	6.28	5.95	5.62	5.28	4.95	3.61	2.01
3. Retail % (approx.)		95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
4. Retail Revenue Requirements		$13.27	$12.95	$12.63	$12.32	$12.00	$11.68	$11.36	$11.05	$10.73	$10.41	$10.09	$9.78	$9.46	$9.14	$8.83	$8.51	$8.19	$7.87	$7.56	$7.24	$6.92	$6.60	$6.29	$5.97	$5.65	$5.33	$5.02	$4.70	$3.43	$1.91

Evaluated Cost Calculation for PRB Coal

(nominal $/ton unless otherwise labeled)

Year	Spot Coal Price for 8,800 Btu/lb. PRB Coal (1)	Rail Rate (PRB to St. Louis, railroad cars) (2)	Rail to Barge Transloading (3)	Barge to IMT (4)	Transloading & Blending Fee (5)	Dixie Fuels Transport Rate (6)	Delivered Price for PRB Coal ($/ton) (7)	Delivered Price for PRB Coal ($/MMBtu) (8)	Net Operating Cost Penalty for PRB Coal ($/MMBtu) (9)	Evaluated Price for PRB Coal (Operating Costs Only, $/MMBtu) (10)	Capital Recovery Requirement for PRB Coal ($/MMBtu) (11)	Evaluated Price for PRB Coal (Including Capital Recovery Requirement, $/MMBtu) (12)
1996	$5.00	$12.83	$0.75	$6.50	$5.16	$7.78	$38.01	$2.16	$0.07	$2.23	$1.13	**$3.36**
1997	$4.36	$12.83	$0.78	$6.91	$5.42	$8.27	$38.56	$2.19	$0.07	$2.26	$0.42	**$2.68**
1998	$4.01	$12.83	$0.82	$6.88	$5.40	$8.24	$38.17	$2.17	$0.07	$2.24	$0.42	**$2.66**
1999	$4.63	$12.83	$0.85	$6.52	$5.16	$7.81	$37.80	$2.15	$0.07	$2.21	$0.32	**$2.54**
2000	$4.54	$11.20	$0.89	$6.88	$5.39	$8.24	$37.14	$2.11	$0.07	$2.18	$0.32	**$2.50**
2001	$4.66	$11.20	$0.93	$7.97	$6.09	$9.54	$40.38	$2.29	$0.07	$2.36	$0.32	**$2.69**
2002	$11.30	$11.20	$0.97	$7.93	$6.07	$9.49	$46.95	$2.67	$0.07	$2.73	$0.31	**$3.04**
2003	$7.08	$11.20	$1.01	$7.84	$6.01	$9.39	$42.53	$2.42	$0.15	$2.57	$0.31	**$2.88**
2004	$6.09	$11.20	$1.05	$5.81	$5.84	$6.96	$36.95	$2.10	$0.15	$2.25	$0.27	**$2.51**
2005	$6.57	$15.51	$1.10	$5.31	$5.84	$6.36	$40.69	$2.31	$0.09	$2.40	$0.29	**$2.69**

Delivered Cost Calculation for CAPP or Imported Coal, and Comparison with PRB

(nominal $/million Btu unless otherwise labeled)

Year	Price of CAPP or Imported Coal Delivered to IMT (1)	IMT Transloading Fee (2)	Dixie Fuels Transport Rate (3)	Delivered Price for CAPP Coal (4)	Evaluated Price for PRB Coal (Including Capital Recovery Requirement) (5)	Differential (6)	CR 4&5 Tbtu (7)	Blend Ratio (% of Btu) (8)	PRB TBtu (9)	PRB Tons (millions) (10)	Damages ($000) (11)
1996	$1.69	$0.17	$0.31	**$2.16**	**$3.36**	**($1.20)**	87.5	10.0%	8.75	0.50	($10,504)
1997	$1.63	$0.18	$0.33	**$2.14**	**$2.68**	**($0.54)**	100.0	23.4%	23.40	1.33	($12,714)
1998	$1.67	$0.18	$0.33	**$2.17**	**$2.66**	**($0.49)**	92.5	25.4%	23.50	1.33	($11,494)
1999	$1.67	$0.17	$0.31	**$2.14**	**$2.54**	**($0.40)**	92.5	33.1%	30.62	1.74	($12,150)
2000	$1.65	$0.18	$0.34	**$2.17**	**$2.50**	**($0.33)**	92.5	33.1%	30.62	1.74	($10,164)
2001	$2.11	$0.21	$0.39	**$2.71**	**$2.69**	**$0.02**	90.0	34.0%	30.60	1.74	$707
2002	$2.22	$0.20	$0.37	**$2.80**	**$3.04**	**($0.25)**	80.0	40.0%	32.00	1.82	($7,914)
2003	$2.16	$0.20	$0.37	**$2.73**	**$2.88**	**($0.15)**	80.0	40.0%	32.00	1.82	($4,745)
2004	$2.16	$0.20	$0.28	**$2.63**	**$2.51**	**$0.12**	92.5	40.0%	37.00	2.10	$4,389
2005	$2.61	$0.20	$0.26	**$3.07**	**$2.69**	**$0.38**	93.2	37.0%	34.48	1.96	$13,213
Total Without Interest											**($51,376)**

OPC Alleged Excess Coal Costs	-$116,594,626
Actual Coal Savings (Heller)	$51,376,000
OPC Alleged Excess SO2 Allowance Costs	-$17,928,717
Actual Reduced SO2 Allowance Costs (Dean)	-$15,015,204
Value of Additional MW Production at CR4 & CR5 (Crisp)	$696,963,130
Total Value to Customer	$733,323,926