BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 060658-EI

In the Matter of:

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

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VOLUME 7

Pages 867 through 1086

PROCEEDINGS: HEARING

BEFORE: CHAIRMAN LISA POLAK EDGAR
COMMISSIONER MATTHEW M. CARTER, II
COMMISSIONER KATRINA J. MCMURRIAN

DATE: Wednesday, April 4, 2007

TIME: Commenced at 9:40 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: LINDA BOLES, RPR, CRR
Official FPSC Reporter
(850) 413-6732

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
79	JNH-1	1025	1025
80	JNH-2	1025	1025
81	JNH-3	1025	1025
82	JNH-4	1025	1025
83	JNH-5	1025	1025
84	JNH-6	1025	1025
85	JNH-7	1025	1025
86	JNH-8	1025	1025
87	JNH-9	1025	1025
144	JBC-1	885	885
145	JBC-2	885	885
146	JBC-3	885	885
147	JBC-4	885	885
148	JBC-5	885	885
149	JBC-6	885	885
156	BW-2	1084	1084
157	BW-3	1084	1084
158	BW-4	1084	1084
159	BW-5	1084	1084
160	BW-6	1084	1084
161	BW-7	1084	1084
162	BW-8	1084	1084
163	BW-9	1084	1084

EXHIBITS

NUMBER:		ID.	ADMTD.
164	BW-10	1084	1084
165	BW-11	1084	1084
225	Direct Testimony of James Heller on behalf of FMPA, et al., 9/16/06	993	1025

P R O C E E D I N G S

(Transcript follows in sequence from Volume 5.)

CHAIRMAN EDGAR: Good morning. We'll get started this morning. Before we move into witnesses, any housekeeping matters that we need to take up or that would be useful?

Okay. Mr. Burnett, your witness.

MR. McGLOTHLIN: Well, we do have one housekeeping matter.

CHAIRMAN EDGAR: As soon as I move on, there always is. So, yes, Mr. McGlothlin.

MR. McGLOTHLIN: We've had conversations regarding whether the parties require Mr. Crisp to appear for cross-examination. Mr. Crisp sponsors calculations that pertain to his position with respect to the cost of replacement energy in the event it is determined that using the blend would cause the loss of 124 megawatts from 4 and 5. Of course, the dispute is over whether it is or is not a derate. And if Progress Energy will stipulate that only in the event the Commission determines that there would be a loss of megawatts associated with the blend would Mr. Crisp's calculations have any applicability, then we would have no questions of Mr. Crisp because that would, the limited scope of our inquiry, should he appear on the stand anyway, would be to make that point.

CHAIRMAN EDGAR: Mr. Burnett.

MR. BURNETT: Madam Chairman, I think that's acceptable. I do agree that if this Commission finds that there would be no derate as a factual matter, obviously Mr. Crisp's testimony goes away and is not relevant. If the Commission finds anywhere between one and 124 megawatts, then Mr. Crisp's testimony would apply and a mathematical derivation could be used to determine -- if you find the whole 124, then it would be the number reflected, and anywhere down from there all the way to one the Commission could still use that. But that being clear, I think we have a stipulation.

CHAIRMAN EDGAR: Ms. Bennett?

MS. BENNETT: No objection.

CHAIRMAN EDGAR: No objection.

Commissioners, questions? Comfortable?

Everybody seems to be comfortable. Mr. McGlothlin, you're comfortable?

MR. McGLOTHLIN: All right.

CHAIRMAN EDGAR: All right.

MR. BURNETT: Madam Chairman, if I may, I believe we also can stipulate Mr. Hub Miller. I understand that no one has questions. So if the Commission did not have questions, we would be in a position, as I understand it, to stipulate him as well.

CHAIRMAN EDGAR: Mr. McGlothlin, you're comfortable with that?

Commissioners?

Okay. Then let's take up -- let's start with Mr. Miller's testimony.

MR. BURNETT: We would move it into evidence, and he has no exhibits, Madam Chairman.

CHAIRMAN EDGAR: Okay. The prefiled testimony of Witness Miller will be moved into the record as though read. You said no exhibits?

MR. BURNETT: Yes, ma'am. And may he be dismissed?

CHAIRMAN EDGAR: And he may be dismissed.

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 OF

HUBERT J. MILLER

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Hubert J. Miller, and my business address is 97 Brown Road, Stillwater, New York 12170.

Q. By whom are you employed and in what capacity?

A. I am self-employed as a nuclear safety consultant.

Q. What do you do?

A. I provide nuclear safety consulting services to the commercial nuclear power industry. I serve on safety oversight committees and perform assessments at numerous plants throughout the United States. Among the committees I serve on is the Crystal River Unit 3 ("CR3") Nuclear Safety Review Committee ("NSRC"). I have performed assessments at a number of plants recovering from significant operating performance problems and regulatory infractions. For example, I chaired a special panel of industry experts which was established at the Perry

Nuclear Station to oversee recovery, over a two year period, from events which led the U.S. Nuclear Regulatory Commission ("NRC") to place the Station in the highest category of regulatory concern. In addition, I advise senior company officials and Boards of Directors on safety and security performance issues in the nuclear industry.

Q. What is the purpose of your testimony?

A. I will address the nuclear safety issues associated with bringing Powder River Basin ("PRB") coal onto the same site as Progress Energy Florida, Inc's ("PEF's" or the "Company's") nuclear unit, CR3. Because PRB coal presents certain hazards, such as spontaneous combustibility, potential explosiveness, and dustiness, its potential use at Crystal River must be thoroughly evaluated by the Company to comply with nuclear safety regulations. In particular, I provide my opinion, based on more than 35 years of nuclear experience and 28 years at NRC, as to what assessments NRC would require of PEF if PRB coal were to be considered, as well as how NRC would become involved in those assessments. My testimony is also based on my familiarity with the Crystal River site from my service on the CR3 NSRC.

Q. Please describe your education background and professional experience.

A. I received both B.S. Civil Engineering and A.B. Liberal Arts degrees from the University of Notre Dame, and an M.S. degree from the School of Public Health, University of North Carolina, Chapel Hill. I completed advanced nuclear engineering training at the Bettis Reactor Engineering School while in the U.S. Navy. I am a registered professional engineer in the State of Virginia.

I have been self-employed as a nuclear safety consultant from August 2004 to the present. From 1976-2004, I held various positions at the NRC. I was Administrator of two NRC Regions, where I was responsible for oversight of nuclear power stations, decommissioning sites and radioisotope users. I was Administrator of the Northeast Region (NRC Region I) from 1996 to 2004. Previously, I was in charge of the Midwest Region (Region III). In these positions, I led heightened agency monitoring of performance improvement programs at numerous "problem" sites. In addition to directing safety and security inspections, I frequently dealt with other government agencies, elected officials and public groups on emergent issues. This included testifying before Congressional Committees examining post-9/11 security measures and emergency preparedness. I began my career at the NRC in 1976 where I worked on the development of waste management regulations and policy, as well as oversight of Department of Energy high level waste activities (Yucca Mountain). From 1984 through 1987, as a senior executive in NRC headquarters, I led development of several quality assurance initiatives applicable to new plant construction. I served in the U.S. Navy at the Division of Naval Reactors from 1970 to 1975, where I was involved in naval reactor plant design and testing, as well as shipyard performance audits.

Q. Please summarize your testimony.

A. I believe risk assessments would be needed if use of PRB coal is to be considered. As I understand it, PRB coal is prone to spontaneous combustion and dustiness, as well as explosiveness. Based on these hazardous tendencies, before a significant amount of this coal can be used at the Crystal River Energy Complex, near CR3, NRC regulations require a detailed analysis of the risks posed by this PRB coal and whether any mitigating strategies can be employed to reduce those risks to an acceptable level.

In addition, based on my experience at the NRC, I can say that the NRC would likely show strong interest in any evaluation conducted by the Company regarding the use of this PRB coal at the Crystal River site. This interest would likely include oversight during the evaluation process, even if a formal license amendment application to the NRC is ultimately not required. The NRC will want to be involved at some level and ask questions during the analysis of potential hazards PRB coal use would present to CR3 operation.

I know of no other nuclear facility that operates on the same site as a coal unit that burns PRB coal, and I likewise am not aware of any licensed nuclear operator ever analyzing the particular risks presented by such coal. NRC safety assessments of licensed operator proposals are considerably more straightforward and timely where precedents exist, than assessments of cases such as this one, where there is no precedent. To use this PRB coal at the Crystal River Energy Complex, PEF must present a compelling case that stringent monitoring methods, controls, and mitigating measures could be instituted to assure the activity would not impact safe CR3 operation.

II. GENERAL OVERVIEW OF NRC REGULATORY FRAMEWORK

Q. Have you reviewed Jon Franke's testimony in this proceeding?

A. Yes, I have read Mr. Franke's testimony.

Q. Do you agree with Mr. Franke's description of the regulatory regime with which PEF, as an operator of a nuclear facility, must comply?

A. Yes, Mr. Franke has accurately described the regulations and requirements imposed by the NRC on nuclear plant operators like PEF.

Q. Would you like to add anything to Mr. Franke's description based on your experience with the NRC?

A. I would just like to expand on some key features of the NRC's inspection and regulatory oversight program -- the methods by which NRC assures its safety requirements are being met. It starts with highly qualified resident inspectors who are assigned on a full-time basis to each nuclear power plant. They inspect routine activities, such as testing of various safety equipment and functions. They also monitor plant activities on a daily basis to assure NRC is aware of emergent issues and new developments and verify they are properly addressed for their impact on nuclear safety by the plant operator. Resident inspectors are backed up by region-based specialists who conduct periodic inspections and technical assessments of events and potential safety issues that emerge. Beyond the

Region, technical experts in NRC headquarters offices conduct reviews of licensing proposals and support the regions in analyzing unique, complex safety issues that arise. Finally, special teams, composed of NRC inspectors and technical experts, conduct inspections. These special team inspections examine, in depth, selected plant activities on a periodic basis as well as operating problems and events that might occur.

Q. As Regional Administrator at the NRC, how involved were you in the operation of each nuclear unit in your region?

A. While I was Regional Administrator, I was responsible for the activities of both the resident inspectors and the region-based specialists. I received daily briefings on plant events, significant activities and inspection developments. I frequently visited sites to assure inspection programs were properly conducted and discuss important safety and plant performance issues with licensee management. Together with other senior managers in my region and NRC headquarters, I played an active role in the assessment of licensee performance issues as well as unique safety issues that would arise at plants. I led the response to events at plants in my region, which involved close monitoring from our incident response center and on-scene oversight by inspectors.

III. ASSESSMENT OF RISKS ASSOCIATED WITH PRB COAL

Q. Have you reviewed Rod Hatt's testimony in this proceeding?

A. Yes, I have read Mr. Hatt's testimony, specifically as it relates to the characteristics of PRB coal and the risks that those characteristics create.

Q. What is your understanding of the risks and characteristics of PRB coal?

A. I understand from Mr. Hatt's testimony that PRB coal is susceptible to spontaneous combustion. I understand that this can be caused by a chemical reaction that occurs when PRB coal is wet, such that the wet PRB coal can catch on fire and then continue to be fueled by whatever dry PRB coal happens to be near it. Further, PRB coal is apparently classified as explosive. What's more, PRB coal has a tendency to break down rather easily, and thus creates significant amounts of dust. That PRB coal dust is also flammable and potentially explosive. It can be carried by wind some distance from areas where it is stored and transported.

Q. Can you comment on the risks that PRB coal poses to safe operation of CR3?

A. Certainly. I believe PEF would need to take steps to comply with NRC regulations before the PRB coal could be brought onto the Crystal River site for long-term use. This includes the 10 C.F.R. 50.59 requirements. Briefly, any change to a nuclear facility, or in the environment near the facility, that can change the nature or likelihood of risks that were assessed in authorizing the facility's initial operating license, must be assessed pursuant to this regulation. Specific, potential impacts to CR3 would need to be addressed in the assessment.

This includes control room habitability, loss of offsite power, degradation or loss of diesel back-up power supplies and other vital safety equipment and safety controls. I understand from reading Mr. Franke's testimony that the Company would consider these potential impacts to CR3 in its assessment of the risks posed by PRB coal on site. The uniqueness of the case would make the assessment challenging for both PEF and the NRC.

Further, I believe that, given the unique and potential serious nature of the hazards of PRB coal described by Mr. Hatt, it is possible that formal NRC review and approval would be required.

IV. NRC REACTION TO ANALYSIS OF PRB COAL

Q. Given your experience as a Regional Administrator at the NRC, do you have an opinion as to how the NRC would likely view or become involved in an assessment of this PRB coal by PEF?

A. Yes, even if a formal license amendment application did not have to be submitted to the NRC, the NRC would have a strong interest in PEF's assessment of the risks. NRC would be concerned with PEF's evaluation of both the hazards posed, as well as the special controls and mitigating measures instituted to ensure that the PRB coal did not present an undue risk to nuclear plant safety. The bottom line is that PEF would need to present a compelling case that, if PRB coal were to be used on a long-term basis, stringent monitoring methods, controls, and mitigating measures could be instituted to assure that the activity would not impact safe CR3 operation.

As a practical matter, plant operators normally take the initiative and brief NRC inspectors and managers of significant developments, such as these, and discuss potential risks that might be posed. Even if this were not done, NRC resident inspectors would almost certainly become aware of such plans and would engage company officials on details to assure the 10 CFR 50.59 screening assessments were properly performed. I would expect key regional and headquarters staff and managers would be advised of the plans. This often sparks further questions. There is no requirement that NRC review all 50.59 evaluations performed at a plant. These are sampled by inspectors. Given the nature of PRB risks, I would expect this case would get reviewed not only for its impact on nuclear safety equipment but for its potential impact on vital plant security functions.

Of course, if following 10 CFR 50.59 assessments, it was determined formal NRC review and approval of a license amendment would be necessary, significant technical reviews would ensue. As I mentioned earlier, I would expect these would not be routine given the uniqueness and nature of risks involved. NRC would thoroughly review the controls and mitigating measures that the company would propose to assure use of PRB coal would not pose undue risk to the public. There would likely be, at least, one round of questions from NRC technical reviewers that would need to be answered through formal correspondence. NRC's license amendment process offers opportunity for a public hearing and requires consultation with appropriate state officials. After all questions from reviewers are answered, NRC would make its decision. The basis for the decision, whether it is approval or disapproval, would be recorded in a safety evaluation report. To approve the proposal, NRC would have to independently establish, with reasonable assurance, that the amendment would not endanger the health and safety of the public and that proposed activities would be in compliance with NRC regulations. The length of time it takes to complete this process can vary, but it can take as long as a year or more.

Q. If a nuclear power plant in your region had assessed the risk of PRB coal while you were Regional Administrator, how would you have responded to this evaluation?

A. I would have been very interested in this issue, given what I understand about this coal from Mr. Hatt's testimony. I would look for assurances from my staff that they were involved enough in the matter to assure PEF was doing the right assessments and that regional staff was in a position to provide an independent perspective on the risks. I, or one of the other regional office senior executives, would very likely be briefed on the matter. We would take steps to obtain any additional expertise that might be needed to provide competent, technical oversight. In short, with the assistance of my staff and regional managers, I would assure that stringent mitigating measures to control and limit the hazards posed by the PRB coal were established before the PRB coal could be used on a long-term basis near the nuclear facility.

Q. What would NRC do if PRB coal fires or other, related problems were to occur and threaten CR3 operations?

A. It would depend upon the severity of the problem. Fires that would threaten but not actually impact on CR3 operations would be closely monitored by resident inspectors and regional staff. If fires, significant accumulations of coal dust, or other aspects were to actually impact on plant safety or plant security functions (which are vital in this post-9/11 world), NRC would escalate its attention and involvement. If failures of significant safety equipment were to occur and result in a plant shutdown, or if security functions became impaired, NRC would very likely conduct a special inspection. Depending upon the severity and complexity of the event, NRC might expect the plant to be held in shutdown status until the matter could be thoroughly examined and corrective actions taken.

NRC would then assess company performance in accordance with its reactor oversight program. Failure to adequately control the risks could result in significant, additional regulatory action. Experience shows that it can take considerable time and additional money to recover a plant from heightened regulatory oversight status.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

MR. BURNETT: And to the extent we need to move Mr. Crisp and his exhibits, we would do so now.

CHAIRMAN EDGAR: Okay. The prefiled testimony of Witness Crisp will be entered into the record as though read And I see six exhibits, 144 through 149.

MR. BURNETT: Yes, ma'am.

CHAIRMAN EDGAR: Exhibits 144 through 149 will be entered into the record as evidence.

(Exhibits 144 through 149 marked for identification and admitted into the record.)

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 OF

JOHN BENJAMIN CRISP

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is John Benjamin Crisp. My business address is 299-First Avenue North, PEF 121, St. Petersburg, FL 33701.

Q. Please tell us how you are employed and describe your background.

A. I am employed by Progress Energy Florida, Inc. ("PEF" or the "Company") currently serving as the Manager of Energy Efficiency Services. Prior to this role, I was PEF's Director of Generation Planning for Progress Energy Florida, as well as the Director of Generation Planning for both of Progress Energy's regulated utilities. My background includes over 20 years of electric utility experience in generation and fuels planning, load forecasting, generation construction, plant operations, system grid planning and operations, fuels and power trading, and energy efficiency systems. I have a bachelor's degree in Industrial Engineering from Georgia Tech, and have coals. I understand that Mr. Hatt will testify that, if the Company had purchased and burned a 50/50 blend of PRB coals and bituminous coals from 1996 to 2005, the units would have each produced on an average annual basis only 665MW gross, rather than the actual net annual energy production of 722MW (winter) and 732MW (winter) that we expected the units to produce over this time period. I further understand that Mr. Hatt's testimony is supported by the same design documents relied upon by OPC's consultant that demonstrate the design rating of the turbines using a 50/50 blend of PRB and bituminous coals is 665MW. I have, accordingly, determined the cost to the Company to replace 124MW annually from 1996 to 2005, if CR4 and CR5 produced only 665MW gross each rather than the net 712MW (winter) and 732MW (winter) they were expected to produce annually over the 1996 to 2005 time period.

Q. Please describe how your background gives you the technical expertise necessary to support your testimony.

A. For much of the time from 1996 to 2005 it was my job as director of resource planning for PEF to find the most cost-effective alternatives to meet the Company's obligation to serve our customers' short- and long-term needs for electric energy. I oversaw the completion of the Company's TYSPs, which set forth the Company's plans to meet customer load over a ten year period of time, presented and explained many of them in the annual Commission workshops held to evaluate the TYSPs, and further supported them during the Commission's determination of their adequacy, which the Commission by law must determine annually.

To perform these responsibilities, I routinely examined and evaluated both supply-side resources, i.e. additional generation, and demand-side resources to meet the customers' demand for electric energy (or load). In the course of this evaluation I analyzed PEF system load and load service reliability requirements, integrated generation dispatch economics, electric system planning and reserve margin requirements, electric generator costs, construction and associated installation costs, fuel and operating costs, generating unit start-up costs, and market replacement capacity and energy. In other words, it was my responsibility to recommend a course of action to build new generating plants, purchase power on the market, or employ new or expanded demand-side measures to reduce demand during peak periods in order to ensure that the Company adequately met the customers' electrical energy needs in the most cost-effective manner. I am employing the same analysis I performed over the years for PEF to determine the most cost-effective manner to meet customer demand for electric capacity and energy to my analysis in this testimony.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. The following exhibits were prepared by me or under my supervision and control, or they represent business records prepared at or near the time of the events recorded in the records, which records it was a regular practice for me or those who worked with me to keep to perform our responsibilities for the Company:

- Exhibit No. ___ (JBC-1), which are the Babcock & Wilcox Company design documents for the boilers for CR4 and CR5;

- Exhibit No. ___ (JBC-2), which is the Company's 1995 TYSP;
- Exhibit No. ___ (JBC-3); which is a composite exhibit of Schedule 1, Existing Generation Facilities, to the Company's TYSPs for the years 1996 to 2005;
- Exhibit No. ____ (JBC-4), which is PEF's daily total load forecast with the generation;
- Exhibit No. ___ (JBC-5), which is the cost estimate for the two-year "bridge" contract costs and remaining eight-year system costs following the construction of a peaking unit to replace the lost 124MW from the CR4 and CR5 de-rates over the ten-year period of time; and
- Exhibit No. ____ (JBC-6), which is the summary of my calculation of the range of costs the Company would have incurred to replace 124MW of base load capacity over the time frame from 1996 to 2005.

All of these exhibits are true and correct.

Q. Please summarize your testimony.

A. I understand that OPC's consultant has testified that PEF should have purchased and burned a 50/50 blend of PRB sub-bituminous and bituminous coal at CR4 and CR5 from 1996 to 2005. I further understand that PEF's expert, Mr. Rod Hatt, has concluded that, if PEF had converted to a 50/50 PRB/bituminous coal blend in CR4 and CR5 from 1996 to 2005, the units would not have produced the MWs they historically have been expected to produce in our TYSPs from burning bituminous coals in the units. Rather, according to Mr. Hatt, CR4 and CR5 together would have generated 124MW less than the net MW expected from the two units each year in the

TYSPs. This de-rate or loss of load is consistent with the turbine rating (665MW) in the boiler design documents using an equal blend of PRB sub-bituminous and bituminous coals included in Exhibit No. ___ (JBC-1) to my testimony. Based on these conclusions, I have determined that, over the eleven-year period between 1995 and 2005 when this loss of net MW load would have occurred, PEF would have incurred $696.9 million to $966 million to replace the lost energy and capacity associated with this MW loss of base load generating capacity.

III. HISTORICAL RESOURCE PLANS 1996-2005

Q. Let's start at the beginning of this time period, what was PEF's generation supply to meet generation demands in 1995?

A. In 1995, PEF's own generation consisted of a nuclear generation unit, fossil steam generation units, and combustion turbine generation units with 7,400MW of electrical generation capacity. In addition, PEF purchased an additional 1,500MW of generating capacity from other investor owned utilities and qualifying facilities. This is demonstrated by the Company's 1995 TYSP in Exhibit No. ____ (JBC-2) to my testimony.

The Company's generation capacity consisted of base load, intermediate, and peaking generation units. A base load unit is one of the Company's most efficient electrical energy generators and, therefore, they are operated at all times except when they must be taken off line for maintenance or repairs. A base load unit typically has higher relative capital costs and lower fuel costs relative to other types of generating units. Peaking units, on the other hand, have lower capital construction costs but higher fuel costs and, thus, are operated during the periods when the demand for energy on the system is greatest or, in other words, the peak times and, hence, the name "peakers" or "peaking" units. The Company had approximately 2,700MW of natural gas and oil fired peaking generation in 1995.

Intermediate generation units, as the name suggests, are operated more than peakers but less than base load units, typically on a seasonal basis. At this time, approximately 1,600MW of fuel-oil fired steam capability served as the seasonal base load or intermediate generation.

In 1995, approximately 3,100MW of the total electrical generation capacity was base load generation located at the Crystal River site. This includes the nuclear unit and the four coal-fired generation units, including CR4 and CR5. This base load generating capacity provided and continues to provide the backbone of PEF's low-fuel cost, base load generation capability. CR4 and CR5 provided about one-half of this base load generation and, thus, were and are critical to supplying the base load needs of PEF's customers.

PEF also had demand-side management resources ("DSM") that were used to reduce demand during peak time periods by, for example, allowing the Company to turn off participating customers' pool motors and water heaters for a fee or credit on the customers' bills. DSM was a result of the Florida Energy Efficiency and Conservation Act ("FEECA") of 1980. Pursuant to FEECA, PEF employed a robust DSM program, with over 1,500MW of load management and conservation capability.

Accordingly, at the end of 1995, PEF had generation and DSM resources available to it equal to approximately 9,095MW of electric capacity and energy supply. This capacity was needed to meet the projected load for 1996 of 9,007MW. The load is the amount of customer demand for energy on the system, typically measured at the peak time period in the year because of the utility's obligation to supply adequate energy instantaneously at all times to meet energy demand.

Q. You used the terms electric "capacity" and "energy." What do they mean?

A. The term "capacity" refers to the commitment of a particular generation unit output or system of generation unit output to provide service. When a regulated utility builds a generation unit, all of the energy output or "capacity" is committed to the utility to provide electric service to customers. Such a commitment ensures that the customer has reliable electric service. If the capacity of a unit is not committed to the utility for service, which can occur in some contracts for purchase power from other utilities or non-utility generators, then that electric service is less reliable because the purchasing utility has no right to call on that capacity for electric energy at its discretion. Contracts with the generation capacity committed to the purchaser are called "firm" contracts and contracts without such a commitment are called "non-firm" contracts.

All or some of a generation unit's capacity, however, can also be and is sometimes sold on the non-regulated market to generation buyers or between regulated utilities in wholesale transactions. The capacity charge, as a regulated or non-regulated cost, represents the fixed cost portion of the generation unit or energy supply source. This cost represents the depreciation of the asset over time. The capacity charge has typically been booked or represented on a $/kW-month basis.

The term "energy" represents the actual electrical output of a generation unit or system of units. The energy charge would cover all of the variable costs to actually generate electricity, including fuel and operation and maintenance ("O&M") expenses, from the generation unit or system of units. The energy charge is also a component of the cost of service. The energy charge is typically booked or represented on a $/kWH basis.

Capacity and energy are both elements of reliable electrical service to customers and must be accounted for when deciding how to provide reliable electric service to the customer, either through building a new generation unit committed to the customers' service or entering into a contract for such service.

Q. Was customer demand for energy expected to grow between 1996 and 2005?

A. Yes. The State of Florida, including PEF's service territory, was and is an area of growth both in additional residents and, thus customers, and customer energy use. PEF expected to have customer growth and an increase in customer energy use during the entire period of time from 1996 to 2005 when it was planning to meet customer needs.

At that time, in 1995, PEF was planning for up to 10,183MW of generation capacity resources by the end of 2005 to meet an expected load of 11,075MW. The additional generation capacity under construction at the beginning of and planned for this time frame was primarily gas-fired generators of peaking or intermediate capability. The Company also planned additional DSM to reduce peak load. The additional DSM was expected to reduce firm peak load from 11,075MW in 2005 to

8,837MW thus ensuring that there was adequate generation capacity resources (10,183MW) to cover the firm peak demand. This data is provided in tabular form for each winter season from 1996 to 2005 at page 80 of the 1995 TYSP in Exhibit No. ____ (JBC-2).

Q. How does PEF plan to meet increased energy demand on its system?

A. PEF employs a resource planning process that integrates supply-side, generation options with demand-side DSM options into a final, optimal plan designed to deliver reliable, cost-effective power to PEF's customers. This integrated, optimal plan is presented to the Commission each year in the Company's TYSP.

In that plan, the need for additional resources is determined by dual reliability criteria: a minimum Reserve Margin planning criterion and a maximum Loss of Load Probability (LOLP) criterion. This reliability criteria has been used since the early 1990's and is a practice accepted by the Commission. By using both the Reserve Margin and LOLP planning criteria, PEF's overall system is designed to have sufficient capacity for peak load conditions, and the generating units are selected to provide reliable service under all expected load conditions.

PEF has found that resource additions are typically triggered to meet Reserve Margin thresholds before LOLP becomes a factor. However, PEF still considers LOLP a meaningful supplemental reliability measure, and the Company is committed to adding resources when either one of the criteria would not otherwise be met.

Q. What is a Reserve Margin?

A. Reserve Margins are "energy service that is held in reserve."

Q. Why are reserves of energy service needed?

A. Utilities require a margin of generating capacity above the firm demands of their customers in order to provide reliable service. At any given time during the year, some generating units will be out of service and unavailable due to forced outages to repair failed equipment or periodic outages to perform maintenance (or, in the case of the nuclear unit, refueling as well). Adequate reserves must be available to provide sufficient capacity when some generating capacity is unavailable for these reasons and when necessary to meet higher than projected peak demand due to the inherent uncertainties in forecasting load and/or abnormal weather. In addition, some capacity must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis.

Q. What was PEF's Reserve Margin from 1996 to 2005?

A. PEF's minimum Reserve Margin threshold was 15 percent up until the summer of 2004. Then, pursuant to a Commission-approved joint proposal from the investor-owned utilities in peninsular Florida – PEF, Florida Power & Light Company, and Tampa Electric Company – the Reserve Margin increased to at least 20 percent. Actual and projected Reserve Margins ranged from a high of 25% to a low of 15% from 1996 to 2005.

Q. How does the utility provide reserves to meet or exceed its minimum Reserve Margin criteria?

A. PEF's reserves can be either physical assets, i.e. constructing generation units or purchasing capacity and energy under contracts with utilities with their generation units, or DSM programs that reduce peak load. Either way, the customers' peak demands for energy are satisfied.

At the end of 1995, however, virtually all of PEF's actual and projected reserves for the period from 1996 to 2005 were in the form of DSM programs. Remember, as I pointed out, by 2005 the Company expected DSM to reduce peak load from 11,075MW to 8,837MW. This was acceptable because the peak periods of demand are relatively brief and, thus, customers might find it acceptable to have DSM measures employed to reduce their energy usage for brief periods of time.

PEF's capacity margins, or the available generation capacity from actual physical or contract generation assets above the peak demand, were about 250MW at any point in time during this same time period. This means the actual physical generation reserves to cover outages and extreme weather on peak days was only about 250MW on average. The remainder of the reserves making up the Reserve Margin was DSM.

Q. How were the reserves used by the Company?

A. Typically, outages or extreme conditions would be covered by available excess generation capacity, and then DSM would be used to offset the remaining need. There were no planning criteria, however, that addressed specific requirements for capacity margins at this time, rather, capacity margin reserves and DSM reserves were treated equally under the Reserve Margin criterion. As a result, the common industry operating practice in 1995 and up until the latter part of the relevant time period was to similarly treat generation capacity equal to DSM when it came to reserves such that often the reserves above the firm peak load were primarily DSM.

Q. Did anything else have an impact on the level and type of reserves during this time frame?

A. Yes. During this planning horizon, PEF's firm load was showing growth faster than its planned capacity additions. This increased the reliance on DSM for reserves in this time period such that the reserves in the last seven years of the ten-year planning period in the 1995 TYSP were almost entirely DSM. In fact, the Company projected net negative capacity reserves in the winter and decreasing capacity margins in the summer to the point where DSM provided all or the bulk of the reserves at all times in these years. The last seven years in the 1995 TYSP were the years 1999 to 2005.

PEF was planning capacity additions to meet load and improve its capacity margins during this planning horizon, with three new gas-fired combustion turbines totaling 400MW of peaking generation planned and approximately 1,200MW of additional, intermediate generation planned in the form of one gas-fired, combined cycle unit and three steam repowering projects. These units were planned because they were economically cost effective, easy and quick to build, required less land and thus had a smaller geographic footprint from an environmental perspective, and they were more flexible from an operational standpoint. The first of these additional generation units, however, was not expected in 1995 to come on line until 1998 with a peaker unit located at Intercession City followed by a combined cycle unit in 1999.

Q. Did the Company's planned Reserve Margin during this time period contemplate continuing base load electric energy generating capacity from CR 4 and CR5?

A. Yes. PEF's resource planning process and thus its Reserve Margins assumed that all generation units, including base load units like CR4 and CR5, would continue to produce capacity and energy consistent with the Company's minimum expectations for those units. De-rates, or a loss of generating capacity and energy from the expected production, were not contemplated in the resource planning process.

Q. Would a loss of generating capacity and energy at CR4 and CR5 during this time period have an impact on the Company's resource plan?

A. Absolutely. A loss of 124MW of base load generation would have been a significant event, given the primary reliance on DSM for reserves and the slim capacity margins during this time period. This loss of additional base load generation capacity from de-rates would have reduced by half the average capacity margin available during this time period. The Company would have been required to take immediate action to add generation capacity to provide reliable coverage of the load to ensure that the customers' energy demands were met.

IV. IMPACT OF CR4 AND CR5 DE-RATES ON RESOURCE PLANS

Q. How did you determine the de-rate would have been 124MW annually?

A. I understand that OPC's witness is testifying that the Company should have burned an equal blend of PRB sub-bituminous and bituminous coal in the boilers for CR4 and CR5 from 1996 to 2005. I further understand that, consistent with the boiler design documents for this blend, PEF's consultant is testifying that, had PEF done what OPC's witness suggests from 1996 to 2005 the maximum, reasonable annual gross MW production from the units would have been 665MW each.

In our TYSPs, based on historical experience with the units, we expected and planned our resource needs on the realization on average of a net 722MW from CR4 in the winter and net 732MW from CR5 in the winter. This is actually the net winter planning numbers for 2000, and the range was from 717MW to 735MW during this ten-year time period, but this 2000 planning estimate for the CR4 and CR5 units is about the average for the time period. Attached as Exhibit No. ___ (JBC-3) to my testimony is Schedule 1, containing the Company's expectations for existing generation facilities for planning purposes in the Company's TYSPs for the time period 1996 to 2005. The winter ratings for these units is appropriate to use here because PEF is a winter peaking utility, meaning that PEF's peak load occurs in the winter.

If I could have achieved at best 665MW from CR4 and CR5 annually from 1996 to 2005 when I planned to achieve, based on historical data, a net 722MW and 732MW, respectively, from the units to meet peak load, the Company would have lost 57MW and 67MW from CR4 and CR5, respectively, each year. This is a total annual MW loss of base load capacity and energy of 124MW.

Q. Is this a conservative analysis of the expected loss of base load capacity and energy?

A. Yes, it is. As I have indicated, the average expected MW output from CR4 and CR5 during this ten-year period was a net 722MW and 732MW, respectively. By "net," I mean the available MW from these units for use by Company ratepayers. The units actually demonstrated the gross production capability of between 750MW and 770MW during this same time period. The difference between the "gross" MW output of the units and the "net" MW output of the units is the MW used by the Company to produce the MW from the CR4 and CR5 units and to support the facilities at Crystal River. The 665MW original design capability on a 50/50 blend of PRB and bituminous coals is a gross MW output. Therefore, using this design basis as starting point for comparison to the net MW output expected from CR4 and CR5 for the Company's planning purposes is a conservative estimate of the expected load loss.

Q. What course of action would PEF have likely pursued in order to mitigate the generation capacity and energy losses from a 124MW de-rate at CR4 and CR5?

A. PEF would have to add peaking generation units to offset the 124MW de-rates at CR4 and CR5. Peaking units would have been the quickest types of generation capacity to add. Peaking units require less space than larger generating units, thus, they can be placed at existing PEF generation sites quickly with little to no additional environmental impact that might delay construction. Such units are further readily available on the market from existing vendors. PEF could add up to 124MW of peaking generation capacity in about two years.

Gas-fired, combined cycles are much larger units and require longer lead times due to the added complexity in the construction of the generation units, and the need for more land for their construction (raising environmental issues too). On average, in 1995 PEF could expect to plan, site, and construct a gas-fired combined cycle generation unit in four to five years. Base load coal and nuclear generation units are complex, large generation plants that require very long lead times to adequately plan, site, design, and construct. The only practical solution, then, to replace an immediate loss of 124MW of base load generation, was to build a peaker.

Q. What would PEF have done to replace the loss of 124MW during the two year period of time required to site, design, and construct a peaking unit?

A. PEF would have purchased short-term capacity and energy from market-based suppliers. During the mid-1990s, a fledgling market for electric capacity and energy was emerging, with a supply of firm and non-firm energy contracts available. As I have explained, a firm energy contract is one in which the generation capacity is committed to the purchaser, and a non-firm energy contract is when it is not. So, there is some risk to the purchaser of energy under the contract that the generation capacity might be unavailable when needed. All of these contracts, whether firm or non-firm, carried with them contractual provisions that imposed some level of delivery risk proportional to market fluctuations on the buyer, meaning that the seller might divert the capacity and energy to other buyers when it was more lucrative to do so because of market volatility.

Q. Were these types of market-based capacity and energy supply contracts cost effective?

A. No, not as a long term choice over self-build generation options. The delivery risk and higher costs of such contracts made them unsuitable for reliable use as capacity or reserve margin supplies over the long term.

In many cases, market volatility caused prices for the capacity and energy to rise above the contract penalty for failure to deliver the contracted for capacity and energy to the buyer, and utility buyers simply would not receive the capacity and energy they purchased. The seller could incur the penalty for failing to deliver to the original buyer and still make more money selling the same capacity and energy on the market to another purchaser. Even for contracts where the energy was backed by a specific generation unit, delivery was not guaranteed without a penalty. Price premiums were added to the peak periods under such contracts, forcing the utility buyers to compensate the seller for the opportunities lost in a volatile market when the seller had to remain committed to the original purchaser. Of course, the utility buyer needs the generation capacity and energy the most during such peak periods, when the buyer is at the greatest risk that the seller will not deliver or that price premiums will be imposed on the buyer.

Additionally, the cost of purchasing these firm or non-firm contracts for generation capacity and energy on the market was higher than the regulated utility's cost to construct new generation. Unregulated project developers building generation units to sell capacity and energy on the market generally incurred higher financing costs because there was more risk associated with the developers and/or their projects than with traditional regulated utility projects. For example, the unregulated generation project assets were "unsecured" since, unlike regulated utility projects, their costs were not incorporated in customer rates. Accordingly, the developers of such projects paid a higher interest premium for financing due to the risk of non-payment if all the generation capacity and energy generated over the life of the unit could not be sold. The interest premium alone could add up to five percentage points to the developer's financing costs compared to a regulated utility's weighted average cost of capital. The project developers further required higher returns for investors to compensate them for the additional risk associated with developing projects in the non-regulated energy market, adding additional costs that must be covered by any contract for the sale of capacity and energy from the generation project.

All of these factors, from the added delivery risk to the purchaser under such contracts to the typically higher costs of the contracts compared to the self-build generation option, made these contracts for capacity and energy unsuitable sources of long term, reliable reserves for a utility like PEF that is obligated by law to provide service to its customers.

Q. Why would you use a market-based contract for generation capacity and energy if the contract cost more than and was not as reliable as building your own generation unit?

A. PEF would have had no choice but to purchase such a contract for generation and capacity and energy if it lost 124MW of base load generation due to a de-rate at CR4 and CR5. PEF would need the contract to "bridge" across the time it takes to build a peaking unit to replace the lost generation capacity.

"Bridge" contracts were available during the relevant time period for a "premium" above the self-generation cost to own the rights to a particular generation unit's capacity and energy for short periods of time, generally less than five years. For example, a regulated utility with cost recovery under base customer rates for new generation might pay $3.75 per kW-month for a self-build generation unit. An unregulated generation unit developer, on the other hand, might charge between $4.50 per kW-month and $5.30 per kW-month for a two-year, firm capacity and energy purchase contract because of the developer's higher financing costs, need for a greater return, lost opportunity value in a volatile market, and the added risk that at the end of the two year contract term there is no purchaser available for another contract.

Q. How long a contract would PEF likely need to replace the loss of load from CR4 and CR5?

A. It is likely that a two-year "bridge" contract for generation capacity and energy would cover the time to acquire the turbines and design and construct the peaking unit to replace the loss of load from CR4 and CR5.

Q. So how would you replace the lost capacity and energy caused by the CR4 and CR5 de-rates?

A. The most reliable and cost-effective path would have been to secure a two-year "bridge" contract for capacity and energy on the market and, during that time period, construct appropriate peaking generation units to replace long term the lost MW from the CR4 and CR5 de-rates. In this way, PEF's customers would be exposed to the market premium costs for generation and capacity for only two years after which time the utility would have a self-build generation unit in place at typical utility regulated costs for the remainder of the relevant time period.

Q. Would the costs of the "bridge" contract represent all costs of generation capacity and energy during the two-year period to bring an additional peaker on-line?

A. No. In fact, it would not be cost-effective for PEF and its customers to rely totally on the capacity and energy under the contract for the entire two-year period of time. This is because the capacity and energy being replaced is base load capacity and energy from units with a high capacity factor, on average a conservative 75% annually.

The capacity factor is the measure of how much time during the year the particular generation unit is operating and providing electrical energy. A capacity factor of 75% means that the unit was operating 75% of the total hours for the year. The cost of capacity under available contracts at the time would have been too expensive at a 75% capacity factor level. Rather, the most cost-effective "bridge" capacity and energy contract the Company could have obtained during this time period would have been for a 20% capacity factor for the energy component under the "bridge" contract. This 20% capacity factor, by the way, is the equivalent of a peaking unit capacity factor. The remaining 55% capacity factor and associated energy would have been supplied by other units in the PEF fleet. This would be true as well for the remaining eight years after the peaking unit was built and operational at the end of the first two years. The capacity factor of the peaking unit would be 20%, thus, the remaining 55% capacity factor from the lost base load capacity would have to be supplied by the balance of the fleet.

Exhibit No. ___ (JBC-4) demonstrates why this is the case. It is a chart of the daily load forecast, in this case 2004 which is during the relevant period of time, over the Company's generation resources. The generation resources are added to meet load based on their incremental cost of producing electricity. The cheapest generation resources on an incremental cost basis are at the bottom of the chart (the base load units) and the most expensive are at the top (the peaking units). If 124MW of base load coal capacity is lost for the entire period of time it would be a slice drawn out of the base load coal level that would have to be replaced at all times by other generation (or purchased) capacity. During the peak periods of time on the chart it is clear that all units, from base load nuclear and coal, to intermediate purchases and oil, to peaking gas and oil units, are producing electricity. At these times, up to the 20% capacity factor of the "bridge" contract and later peaking unit, the peaking capacity cost would replace the lost base load generation. At other times, the remaining 55% capacity factor, the lost 124 MW of base load generation must be made up with additional generation from intermediate oil and gas units, at an additional cost to base load generation.

Q. What would it have cost PEF to build a peaker in 1995?

A. Based on my experience, and on costs for similar generation PEF paid during this time period such as the Intercession City peaking unit that went on line in 1998, the estimated cost to bring on-line an additional peaking unit, including direct and indirect construction costs, construction interest (the allowance for funds used during construction or "AFUDC"), start-up, and inventory costs, is $275/kw or about $56 million for a 200MW peaking unit. PEF actually paid $275/kw to construct the Intercession City peaking unit in 1998. This actual cost to PEF to construct a peaking unit demonstrates the reasonableness of my estimate.

Q. Once the peaker was operational, was the cost of the 124MW additional peaking unit to the system equivalent to the cost of the lost 124MW of base load capacity from the CR4 and CR5 de-rates over this period of time?

A. No. The lost 124MW of base load generation from the de-rates at CR4 and CR5 would be much more valuable in the generation system than an additional 124MW of peaking capacity and energy. The base load variable fuel and O&M costs on a per MW basis associated with the lost 124MW is lower than the per MW variable fuel and O&M costs associated with the peaking unit. This is what distinguishes base load from peaking capacity in terms of capacity factor on the system. The generation system itself would have to "backfill" for the value of the lost 124MW of base load capacity, as I have previously explained and as demonstrated in Exhibit No. ___ (JBC-3), at an additional incremental cost to the customer.

This cost for the remaining eight year period of time following the end of the two-year "bridge" contract is conservatively estimated to be $527,823,360. This includes a capacity cost of $45,116,160 and an energy cost of $482,707,200, assuming that the "backfill" was provided by more efficient thus lower heat rate steam driven units at all times, which would not occur in practice.

Rather, the more likely actual results is that the "backfill" from the system for the lost 124MW of base load capacity at times would have been supplied by less efficient, higher heat rate units, such as peakers. Had I used either an average heat rate or the higher heat rate of the peaking units the costs of the "backfill" energy would have been much higher to cover a loss of 124MW base load capacity and energy, ranging from $639,518,592 (the average heat rate) to $774,676,608 (the higher heat rate).

I also assumed that the energy cost would remain flat over the remaining eight years following the two-year bridge capacity and energy contract to replace the lost 124MW of base load capacity and energy generation from 1996 to 2005. This certainly was not the case over this ten-year period of time, rather, the energy cost, like most other costs, rose over this time period.

I have, therefore, conservatively estimated the cost to provide additional capacity and energy to replace the 124MW lost from the de-rates of CR4 and CR5 at $527,823,360. This is demonstrated by Exhibit No. ____ (JBC-5) to my testimony.

Q. Under your recommended resource plan to replace the lost MWs from the CR4 and CR5 de-rates, what incremental costs would PEF and its customers incur?

A. First, PEF would incur the costs of the 20% capacity under the two-year "bridge" contract. This cost is conservatively estimated at $11.9 million for a two-year 124MW purchase contract. The actual range of estimated capacity costs for this two-year bridge contracts was $11.9 million to $14.9 million. The energy cost component in the power purchase contract is conservatively estimated at $44.6 million for 124MW over the course of the two-year "bridge" contract. The range of these estimated costs were from $44.6 million to $63.8 million. The total capacity and energy cost under the "bridge" contract is therefore estimated at $56.5 million, which, again, is the low-end of the total estimated costs that range up to $78.7 million. See Exhibit No. ___ (JBC-5) to my testimony.

Additionally, there would be the incremental generation system charges to provide the remaining 55% capacity factor associated with a loss of 124MW. This would result in additional incremental charges from the remaining generation fleet of about $112.6 million over the course of the two-year "bridge" contract. See Exhibit No. ___ (JBC-5) to my testimony.

Finally, once the peaking unit was operational, there would be an additional cost to the customer to account for the peaking unit and the fact that the additional 124MW of peaking capacity and energy was not equivalent in value to the system to the 124MW of lost base load capacity and energy from the CR4 and CR5 de-rates. Over the remaining eight-year period of time this estimated capacity and energy cost is $527,823,360 for both the necessary capacity and energy. See Exhibit No. ___ (JBC-5) to my testimony.

The total incremental cost to PEF and its customers from a de-rate of 124MW at CR4 and CR5 over the time period from 1996 to 2005 is therefore conservatively estimated at about $697 million. The range of the cost of this de-rate and loss of base load capacity and energy, however, could be up to and just over $966 million. This is summarized in Exhibit No. ___ (JBC-6) to my testimony.

Q. Do the estimates you have provided account for any fluctuations in these costs over time?

A. Yes, they do. It is true that both the capacity and energy charges can fluctuate depending on the projected use of the generation asset, the amount of fuel consumed, the projected O&M costs, among other factors. Similarly, market prices for capacity and energy can fluctuate in reaction to the costs of equipment, as well as to risks, contract performance requirements, fuel prices, and other cost factors. Accordingly, I have accounted for such fluctuations over this time period in my analysis by coming up with a range in estimated costs for each cost component scenario affected by such variables. The ranges in these scenarios are included in Exhibit Nos. _____ (JBC-5) and _____ (JBC-6) to my testimony. As you can see, in each case with respect to each cost component, I have selected the cost at the lowest end of the range. I therefore believe that my estimate of the total cost impact to the Company for the lost of 124MW of base load generation over the time period from 1996 to 2005 is both reasonable and conservative.

Q. You referenced several power plants being built at or near this time. Why wouldn't you just build bigger plants or speed up the construction plan for those plants? Wouldn't this eliminate the need and associated costs for the replacement 124MW?

A. No, it would not. Regardless of where the capacity and energy come from, the capacity and associated energy will be purely incremental dollars. Speeding up plants or building bigger plants will require relatively similar incremental dollars for construction and fuel, and the impact from construction schedules to build bigger plants will expose the customer to significantly greater purchased power expense. The estimates included in this testimony are reasonable and likely, given the need for immediate replacement capacity and associated energy for the lost 124MW of base load generation from the de-rates at CR4 and CR5.

Q. Does this conclude your testimony?

A. Yes.

MR. BURNETT: And then finally, Madam Chairman, Mr. Heller is available now, so we can take him back up, if it is the Commission's pleasure. We're prepared to bring him on now.

MS. BENNETT: Madam Chair.

CHAIRMAN EDGAR: Ms. Bennett.

MS. BENNETT: We do not have Mr. Windham in the room available, so now would be appropriate to take Mr. Heller.

CHAIRMAN EDGAR: Okay. Does that work for everybody, all of the parties?

Okay. Then let's call Witness Heller.

MR. BURNETT: Thank you.

CHAIRMAN EDGAR: Thank you.

MR. WALLS: Mr. Heller, will you please introduce yourself to the Commission and provide your address.

THE WITNESS: My name is James N. Heller. My address is 4803 Falstone Avenue, Chevy Chase, Maryland.

MR. WALLS: And have you been sworn as a witness?

THE WITNESS: I've not.

CHAIRMAN EDGAR: Okay. Thank you. And let's go ahead and do that. If you would stand with me and raise your right hand.

JAMES N. HELLER

was called as a witness on behalf of Progress Energy Florida and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. WALLS:

Q Mr. Heller, who do you work for and what is your position?

A I work for Hellerworx, Incorporated, and I'm the President.

Q And have you filed prefiled direct and rebuttal testimony and exhibits in this proceeding?

A Yes, I have.

Q And do you have your prefiled direct and rebuttal testimony and exhibits in front of you?

A Yes, I do.

Q Do you have any changes to make to your prefiled direct and rebuttal testimony and exhibits?

A No, I don't.

Q If I ask the same questions in your prefiled direct and rebuttal testimony today, would you give the same answers that are in your prefiled testimony?

A Yes, I would.

MR. WALLS: We request that the prefiled direct and rebuttal testimony of Mr. Heller be moved into evidence as if it was read in the record today.

CHAIRMAN EDGAR: The prefiled direct and rebuttal testimony will be entered into the record as though read.

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. See 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.

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

REBUTTAL 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. Are you the same James N. Heller who previously filed direct testimony in this case?

A. Yes.

Q. What were you asked to do in this testimony?

A. I was asked to review the Direct Testimony of Bernard M. Windham and respond to his statements regarding the delivered prices and tonnages of coal procured by Progress Energy Florida, Inc. (PEF) and by allegedly comparable utilities in the 1996-2005 time period.

II. PURPOSE, SUMMARY AND APPROACH TO TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address certain statements of opinion made by Mr. Windham in his testimony filed in this case on February 14, 2007. These statements include the following:

- Between 1996-2005, it "appears" PEF often did not purchase the lowest price coal, in particular foreign compliance coal;
- It "appears" PEF did not always purchase the lowest available US coal, in particular, Colorado coal.; and,
- Synfuels should have \$2/ton added to its cost to make it comparable to bituminous coal.

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

A. I reviewed Mr. Windham's testimony and materials that he provided regarding the delivered prices of coal to PEF and other utilities. I reviewed similar data from Platts/RDI COALdat on delivered prices. I have previously reviewed information provided to me by PEF on their coal contracts, delivered prices, procurement policies, bids and bid evaluations. I also reviewed Mr. Windham's deposition in this case.

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

A. I reviewed the data on coal deliveries and coal quality to the allegedly "comparable utilities" identified by Mr. Windham, including JEA, Gulf Power

Company, Mississippi Power Company, Alabama Power and Alabama Electric Cooperative, Inc. I also considered information on other utilities identified by Mr. Windham in Exhibit BW-2 as being "Foreign Compliance Coal" purchasers including TECO, New England Power, Public Service Company of New Hampshire, Central Hudson Gas & Electric, and Savannah Electric. I reviewed the delivered prices, quantities and quality of foreign coals delivered to a subset of these plants from Platts FERC Form 423 data. I compared the results of those analyses with information provided in Mr. Windham's exhibits.

Q. Please provide a summary of your testimony.

A. Mr. Windham states that the purpose of his testimony is to "provide basic information related to the delivered prices and tonnages of coal procured by PEF and 'comparable' utilities". He does not specifically address PEF's coal procurement policies and practices during the relevant time period from 1996 to 2005 and does not claim that they were flawed. He also does not calculate any damages. He simply observes that it "appears" PEF "often did not purchase the lowest price coal that met PEF's coal specifications."

In this testimony I will explain the nature of the data that Mr. Windham presents and how it relates to the manner in which PEF procured coal. I will also discuss the quality of the coal being compared in particular the import coals. My conclusion is that while I do not generally dispute the accuracy of the FERC Form 423 data itself, I do question how useful that data is in helping make judgments about the prudence of PEF's coal procurement activities. The delivered fuel price data without additional information reveals nothing about the processes PEF followed in procuring coal and the reasons for the actions that PEF took.

In Mr. Windham's deposition (page 84), he eventually expresses an opinion that, "Based on the information I've seen from the data that I've reviewed and the other information in the docket, I have an opinion that there were years when Progress should have bought more foreign coal." In my opinion, Mr. Windham has done insufficient analysis to draw that conclusion. At the same time, he refuses to express an opinion about the prudence of PEF's actions, so I am a bit confused about what he intends.

Q. Are you sponsoring any exhibits to your testimony?

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

Exhibit No. __ (JNH-9) FERC Form 423 Platts/RDI COALdat Data on coal receipts by various utilities.

This exhibit is true and correct to the best of my knowledge.

III. CRITIQUE OF MR. WINDHAM'S ANALYSIS

Q. What do you understand that Mr. Windham relied upon in preparing his analysis?

A. Mr. Windham relied primarily upon FERC Form 423, PSC Form 423, and PSC A- Schedule data. These databases provide information on monthly coal deliveries and prices to electric generators. The FERC data covers utilities nationwide while the Florida Public Service Commission (PSC) data are filed by investor owned electric utilities subject to PSC jurisdiction.

Q. What is the nature of the FERC Form 423 data?

A. The Federal Energy Regulatory Commission (FERC) requires that each electric power producer for each of its electric generating plants (above 50 MW) report on a monthly basis the cost and quality of fossil fuels delivered to each plant. Exhibit BW-5 presents a copy of the form and instructions. This information is very useful to analysts in understanding what types of coals are purchased for delivery to each of the generating units, the quality of that coal, the source, and the prices paid. However, the form does not contain information as to when the coal was procured or under what circumstances it was procured, other than a "Type" code which indicates whether the fuel is bought on a spot or contract basis and thus provides limited information about what type of contract was used for the procurement.

Q. **Can the FERC Form 423 data be used to determine whether PEF acted prudently in not making more foreign coal purchases?**

A. No. As I explained, the FERC data provide information on the delivered prices paid by an electric generator for coal delivered to a particular plant. The FERC data do not necessarily provide information on the prices at the time that the coal is procured. As a result, the delivered prices reported by two different utilities for the same type of coal in the same month on the FERC form in all likelihood will be the result of coal procurements conducted and contracts negotiated at different periods of time. This means the markets at the time that the contracts were concluded may be quite different for the coal reported as delivered in the same month on the FERC form. The only way to determine if one of the utilities paid more or less than the other for the same type of coal is to know more about each utilities' fuel procurement processes and procedures.

For example, it is important to know whether the purchase resulted from a request for a contract proposal for coal or a spot offer and acceptance; what coal and how much of it was sought in the request and what coal and how much was offered in response; what were the number and extent of the bid responses; what were the market conditions at the time of the procurement; were there circumstances unique to the utility or supplier at the time which gave them the ability to extract higher prices or other concessions; and whether the transportation circumstances affected the pricing. Transportation is a critical issue. Since the reported prices are on a <u>delivered</u> price basis it is difficult to make any judgments about the coal price at the mine until the effects of transportation have been eliminated. The FERC data might be used to show that there should be an inquiry into these other factors regarding the utilities' coal procurement processes and procedures at the time that the coal was procured, but the FERC data cannot and does not provide the answers to the questions regarding these other factors.

Q. Does Mr. Windham attempt to use the FERC data to demonstrate PEF's imprudence?

A. No. He notes that during the 1996-2005 time frame other utilities purchased foreign coals (some of which is of compliance quality), at prices below the average price paid by PEF for compliance coal. He seems to imply that given the size and sophistication of PEF's coal purchasing activities, they should have achieved results at least as favorable as the prices paid by the median of the comparison group. But he maintains in his deposition that he is not testifying that PEF acted imprudently and he does not analyze or address the nature of PEF's procurement policies or practices.

Mr. Windham may be attempting to provide the raw materials to others to demonstrate, if they can, whether PEF acted imprudently. However, he has not provided sufficient material to make that judgment. Mr. Windham admits as much in his deposition when he says he cannot determine how much foreign coal PEF should have bought in any year from 1996 to 2005 and from whom PEF should have bought it based on his analysis. See Deposition of Mr. Windham at page 84, lines 9-25 and page 85, lines 1-16.

Q. Does Mr. Windham offer sufficient information to demonstrate imprudence?

A. No. The manner in which he has constructed the analysis does not comport with the manner in which one would review the prudence of the decisions made by PEF. It is a pure hindsight analysis that purports to focus on results achieved without commenting on what PEF might have done differently to achieve different results.

PEF was clearly aware of and focused on the coal import market; its RFPs included import coal; it received bids for such coals; it did the evaluations; and it bought that coal when it evaluated the foreign coal option as least cost. To make a judgment about the prudence of PEF's decisions, Mr. Windham should have analyzed the circumstances around these bid and procurement decisions to determine if PEF made the right or wrong decision in not buying more imported coal.

Q. Why would one need to analyze PEF's coal procurement decisions at the time they were made?

A. While Mr. Windham's data may show that others were purchasing coal at prices lower than the delivered price paid by PEF, he must determine a number of other factors before he can answer the question about what PEF should or should not have done differently. Were those coals available in the market place at the time that PEF was making its coal purchasing decisions? (It is possible that a producer may sell out, or have a more profitable opportunity at the time of PEF's RFP). Did PEF solicit for those coals and did the potential sellers respond? (PEF can make it known that it is seeking these coals, but they cannot force a producer to bid). Were the prices offered to PEF the same as those offered to others? (Producers will vary the prices that they offer over time depending on shifts in market conditions, their mine operations, and what they perceive to be their competitive position relative to other producers at a customer). These are some examples of what one should consider in a prudence review and they can only be answered by considering all facts and circumstances surrounding PEF's coal procurement decisions at the times that they were made. To my knowledge Mr. Windham has done no such analysis.

Q. What about the PEF comparison price Mr. Windham uses in his analysis. Is that the appropriate price to compare to the other utility prices?

A. No. Mr. Windham in exhibit BW-3 compares the average delivered PEF/U.S. CAPP price with the median of the prices each year paid by his comparison group. He uses the wrong PEF price. This price includes in it the average of all prices paid under spot and contract arrangements which is an inappropriate comparison. In any given year, coals previously committed under contracts at prices established at the time that the commitment was made are being delivered. So for example, PEF may have made a commitment to a CAPP coal in 1994 that had a delivered price of $1.90/MMBtu at the time. The contract was the lowest cost option at the time and the price has since escalated under the terms of the contract to $2.00/MMBtu in 2000. In 2000, the market price of coal may have fallen so that CAPP spot coal is now available at $1.40/MMBtu. PEF buys the CAPP spot coal rather than the foreign coal available that year at the median price of $1.44/MMBtu. Mr. Windham's analysis may well show that the average price PEF paid in 2000 for coal is much greater than the median price of the foreign coal bought by others, but PEF would have done nothing imprudent.

Q. Is there an example of how the PEF comparison price may not reflect current market conditions?

A. Yes, the Massey contract which Mr. Windham discusses shows the problem of comparing current market prices with the prices being paid under older agreements. The long term coal supply agreement between PEF and Massey provided for CAPP coal deliveries at prices which were not directly related to current import coal prices. While the Massey contract may have been the lowest priced alternative at the time it was signed, at a future point in time other lower cost alternatives may have become available as market conditions shifted. Mr. Windham apparently recognizes that problem and posits that the Massey contract could have been reopened to cause the price to readjust to market or the contract could be terminated.

Q. Could PEF have reopened the Massey contract to reject the contract and buy foreign coal?

A. On page 12 Mr. Wyndham notes that the Massey contract "had a reopener about every 18 months at which time changes in the terms could be made by either party with cause". In his deposition, he acknowledges that he does not recall the specific terms of the reopener. He then talks about the commonality of how coal contract reopeners operate. My experience in the hundreds of coal supply contracts that I have reviewed is very different. Market price reopeners are individually tailored in contracts partly because they are very powerful provisions. They may vary in terms, for example of , what triggers the reopener, how frequently they occur, how the price is set once the reopener is triggered, whether either party has walk away rights and when, and how the volume may be reset based on the results of the reopener. It would seem that Mr. Windham would need to review the provisions of this one carefully before commenting on whether PEF prudently administered the terms of the contract.

Q. Have you reviewed the Massey contract?

A Yes. The 1978 contract does contain a reopener, but not one that allows PEF to adjust the price to the level of import coals or unilaterally terminate the contract. It is in my experience an unusual reopener in the specificity of the conditions required to trigger the provisions. Under the "Market Adjustment" provision (section 4.04), PEF must demonstrate to Massey that it is able to purchase coal that is washed, deep-mined, 12,500 Btu/lb. min., .06% sulfur or less, under a ten year contract term with similar terms and conditions to the Massey contract from a non-affiliated producer of similar or larger size than Massey, with similar or better facilities than Massey, and located in Bureau of Mines District 8 (this is central Appalachia). Having met all of those conditions, the offered price must be 15% less than the Massey price during the prior three month period. If these conditions are met, then Progress can propose changes in the base price and escalation provisions. After 180 days of negotiations if they fail to agree, then Progress can terminate the contract.

In 1983, the contract was amended and Section 4.03 "Market Adjustments" became the key provision requiring the parties to negotiate "in good faith" to reach an agreement on a new base price every three years. If they were unable to agree, the contract could terminate, but it required "best efforts to reach agreement". In administration of the contract, I understand that PEF would conduct market price analyses to develop its position on the new base price.

Q. How did Mr. Windham compare the PEF prices with those of the "comparison group"?

A. In exhibit BW-3, Mr. Windham took the weighted average price of all of the PEF compliance coals delivered to IMT (spot or contract) in any given year, and compared PEF's weighted average price with the median of the prices paid by other utilities which imported coal in that year. Based on his deposition, I believe that Mr. Windham included all U.S. utilities which took any foreign coal deliveries in that year. Recognizing that the transportation costs to these utilities could be different than for deliveries to IMT, Mr. Windham chose the median rather than the average value for his comparison. This was an attempt to eliminate the effect of those utilities located in New England, for example, that may have had higher transportation cost components in the delivered price than PEF. This approach would also eliminate the effect of "outliers," meaning reported prices that were for some reason incomparable or in error.

Q. Is Mr. Windham's use of the median price paid for foreign bituminous coal a proper comparison price?

A. No. The use of medians may have made sense if the dataset was comparable and Mr. Windham were simply trying to eliminate the effects of data outliers caused, for example, by misreporting or very unusual shipping conditions. The problem in Mr. Windham's analysis is that the dataset is inherently incomparable, including spot and contract shipments, shipments occurring under contracts negotiated at different points in time, coals that were not of comparable quality, and shipping conditions that varied greatly to mention a few. Simply put, Mr. Windham is not using comparable utility coal prices and, therefore, the use of median price comparisons is inappropriate.

Q. How should the comparison be performed?

A. Ironically, the analysis should be performed in the manner already laid out in the testimony in this case. At the times that PEF went out for bid, they should have evaluated the available alternatives and selected the least cost option on an evaluated basis. The data to analyze this including RFPs and bid responses has been presented in this case along with the testimony of various PEF witnesses explaining the process. The issue which Mr. Windham seems to be addressing in a very shorthand manner through his delivered price comparison has already been addressed properly. The critique must consider the prudence of the decision at the time it was made, and Mr. Windham's analysis does not do that.

Q. Are there any other problems with Mr. Windham's analysis?

A. Yes. There are two issues related to coal quality and the treatment of transportation that deserve further comment.

Q. With regard to coal quality, does Mr. Windham screen the dataset properly?

A. No. The quality of the import coal received by the utilities in his comparison is not always compliance coal partly because some of the utilities in his comparison do not require such coals. This affects both the cost of the coal and the coal sources.

Exhibit No. ___ (JNH-9) is a representative sample of FERC Form 423 data similar to the dataset used by Mr. Windham (all FERC Form 423 data derives from the same utility reporting sources) but Exhibit No. ___ (JNH-9) is FERC data provided by Platts and organized in a different format. The data shown are for imported coals. The utility and plant name are shown on the center of each data grouping and the column headings indicate the data element. The organization of FERC data in Exhibit No. ___ (JNH-9) readily shows the differences in quantity and quality of the import coal in Mr. Windham's analysis.

For example in 1997, the average sulfur content of the 1.385 million tons reported by Mr. Wyndham as received by JEA had an average sulfur content of 1.31#SO2/MMBtu. (Exhibit No. __ (JNH-9), pg. 11). This is not compliance coal and could not be burned at CR4 and CR5. One of the fundamentals of a compliance coal comparison is that all of the coals delivered in the comparison must be of compliance quality. In his deposition, Mr. Windham indicates that he did not screen for compliance quality coals. Often there is a price difference between compliance and non-compliance coals. This is especially true at units like CR4 and CR5 subject to new source performance standards (NSPS). Mr. Windham's analysis does not account for the NSPS impacts on PEF purchases or the price differences between compliance and non-compliance coals.

In addition, some utilities in his comparison also received Australian and Russian coals (e.g. Exhibit No. ____ (JNH-9), pgs. 7, 19), which may not have been offered to PEF as part of its bid solicitations and were never test burned. Mr. Windham does not account for such additional differences in coal quality in his analysis.

Q. Does Mr. Windham do the delivered coal price analysis properly?

A. No. Mr. Wyndham assumes that the effect of the cross-Gulf movement will be identical for all of the coal delivered to a Gulf port. In fact, because these costs are paid on a per ton basis but need to be evaluated on a delivered cents per MMBtu basis, the heating value of the coals does affect the delivered cost comparison. Assume a CAPP compliance coal with a 12,500 Btu/ lb content and a foreign coal with a Btu content of 11,700 Btu/lb are both delivered to IMT. If the IMT handling and the cross-Gulf movement cost is $10/ton, then the transport cost of the CAPP coal is only $.40/MMBtu while the foreign coal costs $.43/MMBtu. The analysis should be done at the plant to properly account for these differences.

This is just one of the problems with the transportation aspects of Mr. Windham's analysis. There are others including variations in vessel capacity, delivery lengths and times, among others, that can impact the comparable delivered price of foreign coal to different utilities. Mr. Windham, however, admits in his deposition that he did not calculate the transportation costs associated with the foreign coal shipped to the utilities in his comparison so Mr. Windham has not considered any of these additional transportation factors in his analysis.

Q. Mr. Windham also comments on Colorado bituminous coal. Do you have a response to that analysis?

A. Yes. Mr. Windham indicates that Colorado bituminous coal was available more cheaply than CAPP coal in some of the years from 1996 to 2005 in an analysis similar to his analysis of foreign bituminous coals. As a result, Mr. Windham's analysis of Colorado bituminous coals suffers from many of the same flaws as his analysis of foreign bituminous coals.

Additionally, PEF's testimony addresses the instance where PEF's own bid sheet analysis of a PEF request for proposal had a low cost Colorado bituminous coal. As Mr. Windham acknowledges in his deposition, the delivered price is not the only criteria that needs to be considered in determining what coal should be procured. In this instance, I understand that PEF did not purchase the Colorado bituminous coal because of concerns regarding known transportation disruptions with respect to western coal. The coal is of no value to the plant unless it can be delivered timely. While one may question PEF's judgment about whether they properly assessed the transportation risks, simply pointing out what PEF already knew that the Colorado coal at one point in time may have been cheaper than CAPP says nothing about the prudence of their business judgment.

Q. Does Mr. Windham comment on any other fuel types?

A. Yes. Mr. Windham indicates that $2/ton should be added to the synfuels price in order to compare it to other coals. With regard to the cheaper pricing for synfuels, Mr. Wyndham's assumption that $2/ton should be added to the price in comparing it with bituminous coal prices seems unfounded. In my experience, the discount for synfuels reflects a sharing of the producer's tax savings with the consumer as an inducement to the customer to purchase synfuels rather than coal. In addition, I understand that PEF blends the synfuels and this virtually minimizes any handling problems. The interrogatory response attached to Mr. Windham's testimony BW-10 addresses the blending solution. Therefore, adding a $2/ton use penalty to the synfuels would be inappropriate.

Q. **Do you have any overall conclusion?**

A. Yes. Mr. Windham's analysis adds no new or useful information to the record to establish or refute the prudence of PEF's activities. To the extent that he attempts to make comparisons they are badly flawed.

A. **Does this conclude your testimony?**

A. Yes.

BY MR. WALLS:

Q Mr. Heller, do you have a summary of your prefiled direct and rebuttal testimony?

A Yes, I do.

Q Will you please summarize it for the Commission, please?

A Yes. My testimony involves the objective determination of, first, what PEC and PFC did from 1996 to 2005, and, second, what the impact would have been on the customer had PFC and PEF done what OPC and Mr. Sansom suggests, that is commit to an equal blend of PRB and bituminous coals at CR4 and CR5 beginning in 1996.

Any prudence determination regarding coal procurement must start with how the utility went about procuring coal and what decisions it made in the procurement process. The beginning point is not what the later reported delivered prices would be on FERC forms months or years after the coal procurement efforts were undertaken and decisions made.

A review of PFC's coal procurement practices and activities showed that they were consistent with industry practice and with what this Commission expected.

PFC began with an assessment of its coal needs after taking into account coals under contract and coals in inventory. Based on this need, the company determined the tons needed and, based on market conditions, decided whether to issue an RFP or participate in the spot market.

PFC had several long-term contracts, as the Commission preferred, and maintained a balance between coals under contract and spot purchases. PFC further maintained dual transportation modes, including rail and water, both as a means of hedging transportation or deliverability risks and as a means of keeping transportation costs as low as reasonably possible. Within the physical limits of the rail and water system PEF sought coals under both transportation means for Crystal River. All of this was reasonable.

During the period between 1996 and January 2006 PEF issued seven RFPs for compliance coals for Crystal River Units 4 and 5, and PRB bids were received in response to four of those RFPs. The RFP solicitation and evaluation processes were nearly indistinguishable. The bidder lists always included producers and brokers of PRB coals, Colorado coals, Central Appalachian bituminous coals and foreign coals, as well as synfuel producers. Notices of the RFPs were printed in coal industry publications, as was the utility's involvement in the spot market. The RFP stated preferences for coal offers but excluded no coals from consideration, except those that exceeded the sulfur restrictions at Crystal River 4 and 5. Not every domestic or synfuel producer bid on every RFP, so it should be no surprise that in response to some RFPs there were no or few PRB bids, Colorado or foreign coal bids. Indeed, if the RFP solicitation process is sufficient to produce PRB bids in response to four out of the seven RFPs, it would seem the process is functioning properly.

I believe everyone here acknowledges that no prudent utility buys coal based simply on the lowest delivered cost. Differences in coal qualities and characteristics can impact boiler operations as well as operating and maintenance costs and can create coal handling and operational issues. These cost differences must be accounted for in making a decision on which coal to buy. PFC initially did this by using an industry standard EPRI model for evaluating the cost impacts of coals with different qualities from the coals that the utility typically burned. This analysis produces what is called an evaluated or bus bar cost.

Looking at the first RFP in which PFC received PRB coals in 2001, the coals were not cost-effective on an evaluated or bus bar cost basis when compared with other options, including foreign bituminous coal, which is what PFC bought at that time.

Had PFC entered into a contract for PRB coals based on the 2001 bid, bid responses, they would have paid three to four times more than the mine price for PRB coals for the prior ten years and more than PRB coals sold for a year later.

In July 2003 and the April 2004 RFPs, PFC again received PRB coal bids. In 2003, these coals ranked behind import coals on an evaluated or bus bar basis, so PFC again bought the import coals. In response to the April 2004 RFP results where PRB coals ranked favorably relative to other options, PFC accelerated efforts to evaluate switching to a blend that included PRB coals.

I understand that the 2004 hurricane season disrupted the utility's evaluation of PRB coals. In my experience in assisting utilities in the evaluation of fuel switching options, it's not unusual that this process occurs over a period of years, particularly with respect to PRB coals which have significant differences in Btu and moisture content and where dusting and spontaneous combustion are issues.

In the second part of my analysis I asked the question, what would have been the impact on customers had PFC and PEF actually done what OPC suggests and converted to an equal blend of PRB and bituminous coals in 1996? I used the same transportation method that Mr. Sansom uses in his damages calculation, transportation of the PRB coals from the mine to the river, loading on a river barge for movement to IMT in New Orleans, and offloading the coal there for storage and reloading on a Gulf barge for the delivery to Crystal River. The differences are that I accounted for all of the costs that PFC would have paid, including terminal charges at IMT, rather than taking costs under different contracts, including transportation costs for TECO and then the Southern Company, before considering for the first time PFC costs in 2004 and 2005 but still excluding the terminal charge.

My transportation costs account for the portion of the regulator or waterborne market proxy that were in effect for PFC and PEF from 1996 to 2003 with a stipulated rate in 2004. This is the way PFC evaluated PRB foreign and domestic coals shipped by water to Crystal River during this time period.

It's not unreasonable for PFC to evaluate coals this way, considering the waterborne proxy applied to all coals actually purchased for CR4 and 5 and shipped by water, including adjustments for portions of the proxy that applied like with foreign coals.

Certainly PFC and PEF took the risk, which the waterborne rate -- when the waterborne rate was in effect, the market costs might actually be higher than the proxy. It's simply hindsight to look back now and say that there were periods where portions of the regulator were above market.

I note further that even Mr. Sansom uses the Gulf barge rate portion of the PEF waterborne proxy in his damages calculation. He simply fails to include the IMT portion of the proxy, although the PRB coals clearly would have gone through IMT. In fact, I understand he fails to include a terminal charge in New Orleans at all.

Also, Mr. Sansom uses TECO's actual waterborne costs in its reported FERC forms when TECO recovered its costs even if TECO's costs were above market, as long as they were below the Commission-approved benchmark.

I also took into account existing contracts and physical delivery limitations on how many PRB tons could be brought in. I also used the real blending costs at the site and the additional capital and operational and maintenance costs that would have been incurred to make the fuel switch as developed by PEF's other experts. I can say, however, based on my experience assisting several utilities in evaluating fuel switches that all prudent utilities consider all capital, operational and maintenance costs in determining whether a fuel switch is cost-effective. Every utility has to account for all of its costs.

Once these costs are included, it's clear that a fuel switch to an equal blend of PRB and bituminous coal at Crystal River Units 4 and 5 would have been a poor decision for the customer over this ten-year period of time, leading to over $50 million in additional costs. This is even before consideration of such additional factors as the value of the lost megawatts of capacity due to the derate from historical production at Crystal River Units 4 and 5 using high quality, high Btu bituminous coals. Other considerations include the ash quality impact, the mercury removal issues under new environmental regulations, and the fact that the company will be scrubbing the units in 2009 and 2011.

When all of these considerations are accounted for, the company's decision to make a fuel switch to an equal blend of PRB and sub-bituminous coals to PRB and bituminous coals does not appear to be a reasonable one. Thank you.

MR. WALLS: We tender Mr. Heller for cross-examination.

CHAIRMAN EDGAR: Thank you.

Mr. McGlothlin.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q Good morning, Mr. Heller.

A Good morning.

Q One of your assignments in the past was, involved an evaluation of Illinois Power's Baldwin Plant; is that correct?

A That's correct.

Q And is it true that in the course of your assignment there you encouraged Illinois Power, the owner of the Baldwin Plant, to look strongly at the possibility of using Powder River Basin coal?

A That's correct.

Q So where economics warrant, you have no reluctance or bias against the consideration of Powder River Basin coal as an appropriate fuel choice for a particular plant; is that correct?

A I missed the pronoun in there. Where the economics are favorable, I have no bias, was that the question?

Q You have no bias or reluctance to encourage the use of Powder River Basin coal if the economics warrant its use; is that correct?

A Right. My consideration is only to a portion of the analysis because I can work on -- I work on the fuel and transportation. The engineering analysis, which is crucial to understanding what the boiler modification, coal handling costs might be, is usually done by somebody else. And so mine is a component input to that.

Q Is it true that with respect to any quantification that you have done in the preparation of your testimony and exhibits you are relying on someone else in this case?

A No, that's not true.

The quantification that I did had to do with the delivered -- the fuel prices and the transportation. I have relied on others for the capital modifications at the plant.

Q Mr. Heller, do you recall that you were deposed prior to your appearance here today?

A I do.

Q Do you have your deposition in front of you?

A No, I don't.

Q Mr. Heller, I'll give you a copy of your transcript of your deposition taken earlier in this docket and ask you to read the answer beginning at Page 31, Line 10.

MR. WALLS: I think in fairness, Mr. Heller should read the question too.

CHAIRMAN EDGAR: Mr. Heller, if you would read the question and the answer, please.

THE WITNESS: Yes, ma'am.

The question begins on Page 7. It says, "As you use the term on Line 10, Page 6, a relatively low Btu high moisture coal like a PRB coal generally has a negative effect on boiler performance."

I'm sorry. There's actually -- my answer before that was a question, so I need to go back one more question, I think, to get the context. I need to read you two more questions and then we'll have the context of this.

CHAIRMAN EDGAR: That's fine. Take a moment. We can work our way through it.

THE WITNESS: The question was, "Did you use the test burn results for any purpose in your testimony?"

My answer, "Not explicitly."

Question, "Is it fair to say, sir, that you don't know personally whether the use of Powder River Basin coal either by itself or in a blend would have a negative effect on the boilers at CR4 and CR5, and that you were relying on others for whatever information you were getting on that subject?"

Answer, "What do you mean by negative effect?"

Question, "As you used the term on Line 10, Page 6," that's in my testimony, "a relatively low Btu high moisture coal like a PRB coal generally has a negative effect on boiler performance."

And this is the answer to that, "For any quantification that I'm doing in this case, I'm relying on somebody else."

That was in the context of the boiler impact of the, the impact of those qualities on the boiler, not on the delivered fuel price.

BY MR. McGLOTHLIN:

Q Well, let's take several items individually then. You treat the subject of capital costs and O&M costs that would be necessary allegedly to burn the blend. Is it true that you did not perform an independent analysis of the capital and O&M costs that would be necessary?

A The blend I assume you're referring to is the 50/50 blend, which is what was proposed by OPC, and for that purpose I relied on Mr. Hatt's estimate of the capital and operating costs.

Q Your testimony and exhibits also touch on the subject of the impact of a derate. Is it true, sir, that you did not perform an independent analysis of whether or not there would be a derate if the blend were used?

A That's correct, I didn't perform an independent analysis. I relied on Mr. Crisp's estimate of the cost of the impact, and Mr. Hatt, I believe, testified about the effect of the low Btu coal on boiler output.

Q Among the materials that were supplied to you as you began your engagement was the Sargent & Lundy report prepared for Progress Energy; is that correct?

A I think in my deposition I was uncertain about that.

Q Well, is it true that you did not review the Sargent & Lundy report in preparing your testimony?

A That's correct. To my recollection, I did not rely on it. And I couldn't remember as to whether or not I had reviewed it.

Q And returning to the subject of the evaluation of impact of particular coals on boiler performance, by that are you referring to the evaluations of bids that were performed by either Progress Energy Florida or Progress Fuels Corporation when conducting RFPs over time?

A I think you mixed two things there and I'm not sure what you mean. I think you were asking me previously about the quantification of what the impact of the PRB coal would be on the boiler in terms of the overall capital and operating costs, and now I think you may have switched to what was called an evaluated or bus bar analysis.

Q I am referring to the evaluated or bus bar analysis of particular coals. And is it true, sir, that with respect to any quantification or calculation of the impact on bus bar costs you relied upon work performed by or for Progress Energy?

A I used information from the bid responses, which have in there a delivered fuel cost and then what's called an evaluated cost. I looked at those and I looked at the difference between the two, which would normally -- which was being used to indicate the impact of the different coal quality of the sub-bituminous coal on the unit, and that's what I used is the amount to adjust the delivered fuel price to produce an evaluated price.

Q But the values that you compared were provided to you and were the result of calculations made by others; is that correct?

A The analysis -- the items that I took out of the bids, I explained which ones I chose out of the bid solicitations and those are in my work papers. And I did go back and I had some information about how to do the calculations. But I could not reproduce them all, so I relied on the company's analysis.

Q If you'll turn to Page 23 of your prefiled testimony.

A Yes, sir.

Q Beginning at Line 6 you respond to the question, "How would companies evaluate PRB coals?" And at Line 19, 18 and 19 you say, "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." Do you see that statement?

A I do.

Q And by more conservative estimates, do you mean that the impact on boiler performance to which the program attributed PRB coal was more severe and resulted in a greater penalty than would a less conservative approach?

A What I meant, in fact, was for the company to be conservative would have meant to be inclusive in terms of, of the PRB bids. In other words, there would -- because the PRB coal is lower in Btu and higher in moisture it carries a penalty; because it's lower in sulfur it gets a premium. This evaluated cost differential is the combination of these various factors, including some others. So if it meant that the company didn't assign a very big differential, it would mean that -- negative differential, it would mean that PRB coal is more likely to be included. And that was the context in which I used the word "conservative."

Q But to be clear, when you say "more conservative," that means a larger negative differential; is that correct?

A No. I think what it means is the opposite, which means once they focused on the Powder River Basin coal more closely, the differentials in later years were larger, as shown in my analysis, which has the effect of making the Powder River Basin coals appear less favorable relative to the Central

Appalachian coals.

Q I think that was my question, but I think the record is now clear.

You described your use of the evaluated bid values in your own work and you said that you used the difference between the evaluated bus bar cost of the PRB coal on the one hand and the bituminous coal on the other as the, as the appropriate measure of the impact of use of PRB coal; is that correct?

A I used the evaluated differential for the limited purpose of, of looking at how one would modify the delivered prices to be on an evaluated basis. I did not include in that analysis, for example, the capital costs that might be required to actually implement the 50/50 blend that OPC is proposing. Those are something greater.

Q And is it true, sir, that in your analysis you used larger negative deducts in the later years because that's what appeared in the bids?

A I missed the last part of your question.

Q In your analysis you used larger negative deducts in the later years because that's what appeared in the bids.

A That's -- it was -- I used what was in the bid sheets, as I explained. And in the bid sheets in the later years the evaluated, the impact of the evaluated analysis shows larger negative numbers. I don't know exactly the source. I don't know quite why that occurred.

Q And is it true, sir, that you weren't able to get much guidance from Progress Energy about how those adjustments were calculated?

A I had some guidance but not sufficient to allow me to reproduce each of those numbers in each year. That information comes out of the, you know, model that they run, which is not one that I have access to. That's also one, I would say, that's commonly used in the industry for doing these kinds of analyses.

Q In your summary you described the activities involved in a conversion of one fuel to another by a utility. Do you recall that?

A Yes. I described that generally.

Q Yes. Would you agree that the activities necessary for conversion are somewhat utility and plant specific?

A The general process or the specific action items?

Q The specific action items.

A Yeah. The specific items are likely to be unique to a particular plant. The general process that's gone through in my experience seems to be relatively similar.

Q Would you agree that one consideration in that plant-specific situation is whether the fuel under consideration is the same fuel for which the units were designed to burn?

A I would -- it's possible that somewhere in the mix of thinking that a utility goes through in determining whether or not to do a conversion is certainly a look at the boiler and the capabilities of the boiler. It's also a look at the coal handling facilities, the environmental regulations. So what you identified is, you know, what is probably buried in one of those items that a utility would, would consider. It's not a determinative one, I wouldn't think.

Q If you'll look at Page 29 of your testimony.

A Yes, sir.

Q Beginning on Page 28 and 29 you discuss your calculation of the transportation component of delivery of Powder River Basin coal; is that correct?

A I describe it on Page 28 and it goes over into 29. That's correct.

Q And at Page 29 you use the term "regulator," do you not?

A Yes, I do, at Line 15.

Q And so that the record is clear, would you take a moment and tell the Commissioners what you mean with the term "regulator"?

A I state later on in that sentence that I use it to mean the waterborne market proxy rate established by this Commission. And what I take that to mean is the amount that Progress Energy was allowed to charge for the waterborne transportation of coal from the mine site to -- or from wherever consideration began, which initially was Central Appalachia down to the Crystal River plant. Later on that was modified by the Commission to include a portion of the waterborne proxy specifically to address imported coals because they would use a different portion of the waterborne transportation route than would the other domestic coals.

Q And with respect both to the original waterborne proxy applicable to moving from the Appalachian area and the modified waterborne proxy applicable to the ocean portion, both of those proxies have been specifically approved by the Commission, have they not?

A The proxy for Central Appalachian coal movements is, is what the original proxy -- it didn't say that, but it appears to have been modeled after -- but it was certainly looking at, you know, domestic coals, as pointed out later.

The -- what you were referring to as the waterborne -- I'm not sure exactly what your term was -- but later on when the company began importing coals into IMT, a portion of the proxy was applied for the movement of those coals from IMT to Crystal River.

Q And both of those proxies have been specifically submitted to and approved by the Commission; correct?

A That's my understanding, yes.

Q Now you have made an adjustment to the waterborne proxy and have used that in your calculation of transportation costs; correct?

A Yes. In order -- yes. In order to apply the waterborne proxy to Powder River Basin coal movements, I laid out a methodology which is intended to mirror or follow the methodology that the Commission used when it approved imported coals, and I applied that to Powder River Basin coal.

Q And it's true, is it not, sir, that your adjustment to the waterborne proxy that you've used in this case has neither been submitted nor approved by the Commission?

A To my understanding, it's neither been submitted nor approved. That's correct.

Q Now your use of the, of your adjusted proxy is one distinction between your calculation of the economics of Powder River Basin coal and Mr. Sansom's; is that correct?

A One of the differences between us has to do with the calculation of the waterborne transportation rates.

Q If you'll turn to Page 30 of your prefiled testimony.

A Yes.

Q Beginning at Line 4 you discuss an analysis entitled Estimated Powder River Basin Origin Transportation Market. And at Lines 9 through 12 you say, "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." Do you see that statement?

A I do.

Q And would you agree with me, sir, that one of those other factors indicative of economic forces would include competition?

A I think embodied in what in a rate setting process in fact is, is competition, that's one of the market forces. The -- I was using that here to explain why the analysis that was done in what I have as Exhibit JNH-4 is different than the analysis that I used. I relied upon information on actual published rates, I'm sorry, published indices for the two relative movements as opposed to simply a distance proportioning.

Q Would you agree that -- in looking at commercial rates you would agree that competition is one of the economic forces that would shape rates.

A Yes, I think competition is one of the forces.

Q I'm going to take a moment and distribute a document.

CHAIRMAN EDGAR: 225?

MR. McGLOTHLIN: Thank you.

(Exhibit 225 marked for identification.)

BY MR. McGLOTHLIN:

Q I've provided Exhibit 225, captioned Direct Testimony of James Heller on Behalf of Florida Municipal Power Agency, September 19, 2006. Do you recognize this as your testimony in what we've referred to as the Taylor project?

A It looks like it.

Q If you'll turn to Page 4 of the document, you answered the question at Line 18, "Describe the approach you took in developing the forecast of rail rates." You want to take a moment and review the answer there, and then I'm going to ask you a question about it.

A Okay. I see that.

Q In your answer you say, "Our forecasting approach was based on a model of bidding behavior known as 'next best' pricing. For any route where competition exists between two or more railroads, the rail rate is assumed to be determined by the lowest amount the railroad with the second-best route is willing to bid. The railroad with the best route would generally be expected to bid just below its estimate of the 'second-best' railroad's bid, in order to maximize the value of its superior route."

Is it fair to say that you adopted in your testimony here and in that case a technique or method of capturing the effect of competition on transportation costs?

A Your question was did I adopt that in that case and in this case?

Q My -- no. I was specific to the docket in which you appeared here.

A Yes. That was how I did -- that was part of how we did the calculations, and that's also how I did it here.

Q Where in your testimony do you have -- have you adopted this approach?

A If you look at the analysis of the rail rates that I used from the Powder River Basin to the river docks, you'll see that there's several different distances and several different docks involved. And the way we applied it was to take a look at the more inefficient route, which is the route to St. Louis, to apply a relatively low mill rate to that, recognizing that that would be the second-best carrier. And if you saw the rates that I have and that Mr. Edwards has and that ultimately UP had, I think they reflect that kind of thinking.

Q In your analysis did you consider deliveries to Mobile and the use of that route?

A In my analysis I was responding to the testimony of Dr. Sansom -- of Mr. Sansom, and Mr. Sansom's testimony had relied on the movements to, as I understood it, to the Mississippi River and then through the Gulf. So I didn't try to develop a separate analysis through Mobile, nor to my knowledge did he. I did look at that route and I think it's problematic. I was aware that there are bids that have been submitted here that are, I think that were discussed. But if you look at those bids to Mobile, they're unusual. One of them is a joint line haul between the BN and the UP, which is virtually undone in this industry. It has a limitation on it of 200,000 tons, which indicates that it was not going to be a, you know, a long-run option.

I talked to the Burlington Northern to see what their view was of handling coal through Mobile, and it's my understanding that that line is limited both in terms of the weight per car and in terms of train length. And, as a result, they consider that route to be relatively unattractive.

But, again, I didn't analyze it. My position here was primarily to respond to Mr. Sansom's work, and he proposed the route through the Gulf. It's actually, by the way -- to my knowledge, the Burlington Northern has actually leased the piece of track. They no longer go directly to Mobile. It was unattractive enough to them that they no longer fully own that line.

Q If I could have a moment in place, I think I'm about to wrap.

You may have said this during your summary, sir, but you referred to a, a transportation proxy that TECO had utilized. That also was a Commission-approved rate, was it not?

A There is a market proxy for TECO that I believe is Commission approved. I'm not sure where in my testimony you were referring to.

Q In your summary. But that's, that's my last question. Thank you.

CHAIRMAN EDGAR: Thank you.

Mr. McWhirter.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Good morning, Mr. Heller.

A Good morning.

Q I'm John McWhirter, and I represent a consumer group, industrial consumer group.

Are you familiar with the working relationship over the years between Progress Energy Corporation and its predecessor Florida Power Corporation and Progress Fuels Corporation and its predecessor Electric Fuels Corporation?

A In a very, very general sense.

Q Uh-huh. Would you describe that relationship as, as far as you understand it?

A Again, in my general sense, Electric Fuels had -- and I'm talking about Electric Fuels had a contract with Florida Power Corporation under which they would provide fuel to Florida Power, and that Electric Fuels was responsible for the procurement of coal and for the delivery of that coal to, to Florida Power. That's very general.

Q Do you know whether other utility companies have the same kind of arrangement with affiliated transportation companies?

A Affiliated transportation companies in particular?

Q Well, it looks like you get many services from

Electric Fuels in addition to transportation. Do you know of other utilities that have that same panoply of services provided by an affiliate company?

A There are some variations that I know of. Tampa Electric has affiliate operations that are involved in the transportation of, of coal to, to its plants.

Q Do you know of other utilities that have that?

A I know that Utility Fuels, which was an arm of Houston Lighting & Power, had an arrangement, and Southwestern Public Service had and may have -- I think had an affiliate called Tuco. I'm not sure what that meant. But I believe they were responsible for some portion of the transportation and coal handling.

Q Do you understand from your experience and study why these affiliated transportation and ancillary service companies are set up?

A I have, you know, I haven't researched them, but I, you know, have some understanding of -- I can give you my opinion as to why, if that's what you'd like, but I don't know for sure.

Q You don't know for sure?

A I don't.

Q I see. Well, I won't probe that, if you don't know for sure.

In your study of the shipments in this case, what --

as a general matter, what portion of the total delivered cost of coal to the Crystal River site was represented by the price for the coal purchased itself and what percentage of the price was represented by the charges imposed by Electric Fuels? Is that question too ponderous for you to ponder?

A The way you asked it, there's a whole range of percentages that would come out. So unless you're more specific, it would be very hard for me to -- I couldn't respond with a percentage.

Q Let me state it sort of in general terms. Is -- does the -- sir, does the cost of coal itself when purchased from a third party represent more or less than 50 percent of the total price charged to Florida Power Corporation and its successor Progress Energy of Florida?

A Let me give you two examples to tell you why I can't answer that question.

Q All right.

A Assume the price of Central Appalachian coal is $60 a ton, which it has been during the time period that we're considering, and the price of transportation, let's say, is 20, then transportation constitutes 25 percent of the delivered price of the fuel.

Now let's say that the transportation cost is $20 and the price of the coal is $40, or $20 -- $30, I can do that math in my head. If it's $30 for the coal and it has been less than that in the time period we're talking about and $20 for the transportation, then transportation would constitute 40 percent of the, of the price.

Q In your Exhibit JNH-7 --

A Yes, sir.

Q Bear with me a minute. JNH-6, which I believe is Exhibit 84 marked for identification, over the period 1996 through 2005 in Column 1 you use the spot price for PRB coal. Can you quickly figure what the average cost for the spot price of PRB coal was during that period of time?

A Do you want me to take a mathematical average of that column?

Q Do I want you to make a mathematical calculation? Just looking at it I think you can come to a conclusion of what the average price was over the ten-year period, can't you?

A You know, a simple average of those numbers would be -- the lowest number I have is $4 and the highest number I have is $11.30.

Q And the $11.30 is way out of line with the rest of them, isn't it?

A That is correct. That occurred during 2001.

Q Yeah.

A And actually at the time the company went out for bid. So if you -- the preponderance of numbers are going to be in the, you know, $5 to $7 range.

Q And using the $5 to $7 range, how would the cost of transportation compare to the cost of coal in those circumstances?

A You're asking me specifically about Powder River Basin coal?

Q Yes, sir.

A And how it would -- Powder River Basin coal in general is a much smaller proportion of the delivered price of fuel. The FOB mine price of Powder River Basin coal is a smaller proportion of the delivered price of fuel certainly to Crystal River and to virtually any plant in the country.

Q I appreciate that. But what I'm asking you is the price charged by Electric Fuels or Progress Fuels relative to the price of spot coal, what would the percentage of the transportation costs be compared to the percentage of the coal?

A If you look at Column 7 on Exhibit 6, you can see that the delivered price for PRB coal is around $40 a ton, varies anywhere from $37 to $46. So if the price is, say, $8 a ton out of $40, that's going to be about 20 percent.

Q The coal price would be 20 percent and the Progress Fuels Corporation price would represent 80 percent of the total cost, delivered cost of the coal; is that right?

A 80 percent would be in the transportation.

Q Yes.

A That's not all Progress Fuels. That includes the, what I have as a rail rate to St. Louis which goes to the railroad, that's actually the lion's share, and then the spot coal price. But I'm telling you that's a phenomenon of Powder River Basin coal. The transportation costs of PRB coal are either almost always greater or always greater than the price of the coal.

Q Well, Progress Fuels would be responsible for transloading and blending and Dixie Fuels' transport rate. And what other, what other portion of the price would Progress Fuels bear in that analysis?

A Are you talking about when the proxy was in place or --

Q I'm talking about your exhibit.

A And I've said it varies year to year. The portions in here that I've used the proxy for are Column 4, which is the barge to IMT, and I'm using a portion of the proxy. And I explain that I've prorated that because the distance is shorter than from Central Appalachia. The transloading and blending fee in Column 5 is the market proxy amount. The Dixie Fuels transportation rate is the market proxy amount.

Q All right. And what percentage would Progress Fuels Corporation represent compared to the price of coal in that circumstance?

A It varies. Just doing -- this is in my head, you know, maybe a third in 2004.

Q 60 percent of the cost would be --

A Maybe 50 percent in another area.

Q Yeah.

A So it would --

Q Uh-huh.

A You'd have to do it year by year.

Q Okay. Well, we won't go into that a little bit more. But you've talked about the proxy arrangement. What is the proxy arrangement as you understand it?

A The proxy arrangement that existed in 1996?

Q Yeah. Well, through 2005. Yes, sir.

A Okay. It varied over time. The proxy, as I understood, that existed in 1996 through 2002 was based upon an amount that had been agreed to by the company and approved by the Commission that provided a certain dollar amount for the transportation of coal. Let's say in 1993 it was from Central Appalachia. And that had within it a component that took the coal from the mine to the river, it was a relatively small amount, then there was a transloading fee at the river, the cost of moving the coal by barge from the Central Appalachian point down to the terminal in New Orleans at IMT, the transloading at IMT, and then the movement across the Gulf to Crystal River. And portions of that movement were handled by affiliate companies. And rather than go back and continually examine how actual costs might change, the market proxy was developed to make it easier to determine how the transportation costs would shift over time without regard to what were necessarily the underlying costs, meaning the company could take, would take the risk that if rates went, barge rates, for example, went through the ceiling, the market proxy might not allow them to recover that. And if they were able to make them less than the proxy, then, you know, the company would, could, could benefit from that. So it was put in place to approximate the cost but to make it easier to regulate it over time.

It's my understanding that that proxy was modified in, I think it was stipulated, I'm not sure I have my years right, in 2003 and then eliminated in 2004, and currently I don't believe there's a proxy. I think the company charges its actual costs.

And at times, because there were affiliates involved in the transportation movement, it became easier to -- it was called a market proxy because the risk would be borne based on changes in market, not necessarily changes in actual cost.

Q If -- did Progress Fuels utilize barges for its transportation, water transportation?

A Barges?

Q Barges, water transportation.

A Did Progress Fuels use barges?

Q Yes.

A It did for some of its movements. It did use barge transportation, yes.

Q And was the market price for rail used as the market proxy in evaluating the charges that were appropriate for the barge traffic?

A In the case of Progress Energy?

Q Yes, sir.

A No. To my knowledge the rail rates weren't explicitly used.

Q What was the market proxy? What -- with a proxy I understand you look at something else to evaluate the value of the service the affiliate is providing. What was the other thing that was looked at to determine the proxy for the services delivered by the affiliate?

A I don't recall all the pieces, but there are -- there is a list of independent escalators, meaning those were things that were under third-party control that were used to adjust portions of the proxy. Let me look. I'm not sure if I have -- actually they're not here. I don't have them in my, they're not listed in my testimony. I think they were in my work papers.

Q All right. In your Exhibit JNH-7, which I believe to be Exhibit 86, in Column 5 you're using evaluated price for PRB coal including capital recovery requirement. What, what does "including capital recovery requirement" mean? What is that?

A There was the -- again, the simulation that I'm doing here, and I'm not saying this is how things would or certainly should be done, in responding to OPC, they posited that this coal would be blended at Crystal River. And in order to do the blending at Crystal River and burn it in the units, as Mr. Hatt has indicated, there are changes that need to be -- capital needs to be invested at the plant. And this includes within the evaluation the capital that would be required to actually affect the, you know, situation that OPC has posited.

Q I see. So that's a fairly substantial amount relative to the overall cost. When you did capital recovery, did you include a return on the investment in the new facilities that Mr. Hatt said were required?

A That's correct. That's in my work papers.

Q Did it include --

A The nature -- I'm sorry?

Q Did you include depreciation?

A There's a capital recovery factor that's used and I think it takes account of depreciation. It's in my work papers.

Q And did you look at the capital structure and determine what portion of the capital structure was equity and what portion was debt?

A That's embedded in the cost recovery factor that was, that's used.

Q Did you ever consider the fact that if the plant had initially been represented to be capable of burning PRB coal, that the capital shortcomings might be the responsibility of the company that represented that it could burn PRB coal rather than the responsibility of people who consumed that, the electricity produced by that coal?

A That's certainly beyond the scope of what I considered. But to the extent that the company was actually going to burn PRB coal at the site in the proportions that OPC indicates, they, like all other utilities, would have to spend substantial capital to do it.

Q And did you make a determination in your analysis of whether that capital recovery should be through base rates or through the fuel clause?

A I did not. That's beyond the scope of what I did.

Q I see. If Column 5 were -- well, in the capital recovery Mr. Hatt used estimates of the cost that range between something like a $40 million investment to something like a $70 million investment. Did you use a $40 million number or the $70 million number?

A His range was between 48.6 and 73.7, and I used the average of those two.

Q So you used something like a return on $60 million?

A It would be about that.

Q I'm not that good at math. You used the average. What was the capital that you used?

A It's in my testimony, and I think it's about 60 million.

Q About 60 million?

Would it be fair to say that if that column were deleted from your analysis, that it would markedly change the results of your conclusions?

A If Column 6 were deleted from my analysis --

Q Column 5. Column 5.

A I'm sorry. Column 5 were deleted from my analysis, then the damages calculation that I have would be, would change; however, the conclusion as to whether or not Powder River Basin coal made sense to be burned during this time period would not. Just the amount of how bad an idea it is would, would change.

MR. McWHIRTER: Thank you. That's all the questions I have.

CHAIRMAN EDGAR: Mr. Twomey?

MR. TWOMEY: No questions.

CHAIRMAN EDGAR: Mr. Brew?

MR. BREW: Very briefly, Your Honor.

CROSS EXAMINATION

BY MR. BREW:

Q Good morning.

A Good morning.

Q On Page 3 of your prefiled testimony, Lines 15 through 17, you say that you have previously done work for Florida Power Corp, Progress Energy and Electric Fuels. Do you see that?

A Yes, sir.

Q Can you tell me for the years we're talking about, 1996 to 2005, in which of those years did you assist any of those companies in the solicitation or evaluation of the coal procurement?

A I never assisted them directly in the solicitation or evaluation of an RFP response. I did provide information to them that I believe was used in the administration of the market price reopeners under some of their contracts.

Q Okay. So you have no personal knowledge of how the companies actually evaluated the coal bids; is that right?

A I have the information from, you know, bid sheets and what's been provided in this record. I don't have an -- I haven't independently participated in that process.

Q But you have no personal knowledge of how they evaluated the bids at the time they were doing it.

A Other than what's in the record, I don't have independent knowledge.

MR. BREW: Thank you. That's all I have.

CHAIRMAN EDGAR: Ms. Bradley? No questions? Questions from staff.

MS. BENNETT: No questions.

CHAIRMAN EDGAR: No questions.

Mr. Walls.

MR. WALLS: Just a couple of minor questions on redirect.

COMMISSIONER CARTER: Madam Chairman.

CHAIRMAN EDGAR: Commissioner Carter.

COMMISSIONER CARTER: I just wanted to ask a question, if I may.

CHAIRMAN EDGAR: You may.

COMMISSIONER CARTER: I was just trying to reconcile this. I think that on yesterday Mr. Hatt made reference to about $80 million in the context of $60 million for the retrofitting at the plant and about $2 million a year for the maintenance operation. It may very well be in his testimony, although I don't think you were here yesterday. And today you're saying that in terms of in addition to that $80 million, just my rough guestimate for the ten-year time frame is that for fuel and transportation there would be an additional $50 million in order to use the 50/50 mixture; is that correct?

THE WITNESS: I have to take a look at my exhibit. I think you're referring to my Exhibit JNH-7. If you look there -- I don't know how it's numbered for the proceeding, but in my testimony it's JNH-7. And the, in the lower right-hand corner there's a negative $51,376,000. That's the $50 million number that I'm referring to. And to tie that to Mr. Hatt's estimate I included both his capital, the average of his capital costs, and I included the $2 million a year that he had for actually doing the blending and doing the operations at the plant. Those numbers are embedded in my calculation of the evaluated price for PRB coal, including capital recovery.

What I've done on Exhibit JNH-7 is for this time period from 1996 to 2005, if I include in there the annual costs associated with the adjustments that Mr. Hatt proposes be made at the plant and I deliver the coal to Crystal River using the adjusted market proxy and the market prices for coal, by my calculation the company would be -- the customers would have paid $50 million more in to use the PRB coal over this time period than they would have by following the -- by actually the results that the company got buying Central Appalachian and imported coal.

So there's some apples to oranges in that Mr. Hatt, when he talks about a capital investment of, say, $80 million, in order to break that out over the years, I have to annualize that. I think Mr. McWhirter was asking me about that. So what I do is I break a piece off of it each year and assign that to the amount of coal delivered that year. So in effect, my negative $51 million has in it both the effect of the cost of transporting the fuel, the Powder River Basin coal down to Crystal River, and the recovery of a portion, not all, but a portion of the capital costs that Mr. Hatt has, has included.

The reason I have only a portion and not all is because that capital would be covered over a long period of time. And if it turns out that these units are actually converted to scrubbers in, I think, 2009 and 2011, this other investment might not be needed, in which case the, you know, negative impacts would be even greater because there would be, you know, there might be no more PRB coal with which to recover that investment. So I have embedded in mine both the transportation, the fuel and the capital recovery portion of Mr. Hatt's.

COMMISSIONER CARTER: Madam Chair.

CHAIRMAN EDGAR: Yes, Commissioner Carter.

COMMISSIONER CARTER: I hear what you're saying about the apples-to-oranges comparison there, but I'm just trying to make sure that I really have the number here. Because from my discussion and questioning is that I was asking specifically what would it cost. I even asked one of the witnesses, I think it was Mr. Weintraub, whether or not it was cost prohibitive even to do this. And I think that the -- from my discussion with Mr. Hatt, he said that it would be $60 million to upgrade CR4 and CR5 in terms of infrastructure and capital improvement costs for the facilities to burn the PRB coal. Secondly, he said in addition to that there will be an annual operating cost of about $2 million. And just my rough guestimate of $2 million over 10 years, that's $20 million. You add that to the $60 million upgrade, that's $80 million.

Then today I'm listening to what you're saying in the context of the transportation costs and the cost of the coal in terms of the spot market and as well as what is available, and because of the run up there's a problem where there was either a supply problem or whatever the problem was with PBR -- PRB coal that shot the price up, I think it went from -- I'm not sure exactly what the charge --

THE WITNESS: It went up on Exhibit 6. If you look on Exhibit 6, it was $11.30 in 2010.

COMMISSIONER CARTER: Yeah. Yeah. So what I'm trying to get my arms around is that when I hear you say $50 million, I'm thinking that this $50 million is dealing with the cost of, the additional cost of the coal plus the transportation costs to get the coal to CR4 and CR5. This is what I'm thinking. Now if I'm wrong, straighten me out.

THE WITNESS: I understand your question. It's going to take me probably about -- it's complicated. It'll take me about five minutes, but I can walk you through how I used Mr. Hatt's costs.

COMMISSIONER CARTER: You got a shorter version and a simpler version? Give me the one-minute simpler version.

THE WITNESS: Okay. Can I take you to -- I need to use my Exhibits JNH-6 and --

COMMISSIONER CARTER: Sure.

MR. BURNETT: Commissioner, Mr. Walls speaks Mr. Heller's language, and a couple of redirect questions may be able to clear this up if we could translate it from --

COMMISSIONER CARTER: Do you understand what I'm asking?

MR. BURNETT: I understand. Absolutely, sir.

COMMISSIONER CARTER: Okay. Good. That's fine. If we can bring it out in redirect.

CHAIRMAN EDGAR: Okay. Let's go to redirect. And then, Commissioner Carter, if you have follow-up questions, we will, we will go there.

Mr. Walls.

MR. WALLS: I hope I can address your questions.

REDIRECT EXAMINATION

BY MR. WALLS:

Q Mr. Heller, have you taken the full number that was provided by Mr. Hatt in order to do the capital upgrades and the maintenance costs to both blend and operate onsite, if you brought 100 percent PRB onsite and burned in a 50/50 blend, into consideration in your calculations?

A Yes. I've taken into account both his full capital costs, the $60 million and the $2 million a year over ten years. Both of those are included in my calculation.

Q And all of that money would have to be spent under your calculation; correct?

A All that money would have to be spent. That's correct.

Q And it would be incurred in the first year when they made these improvements; right?

A The $60 million would be incurred in the first year. The $2 million a year would be incurred, $2 million a year over ten years.

Q But you wouldn't necessarily recover that $60 million that first year; right?

A No, you would not.

Q You would have to recover that over what period of time?

A I think the capital recovery factor that's used is 20 years, but I'm not certain. It's something that the company has embedded, I believe, in their capital recovery factor, but I'm not sure. I guess it would be 20 to 30 years.

Q And so what you're looking at in your exhibit from 1996 to 2005 is a portion of that time period; right?

A That's correct. I'm only looking at ten years of it.

Q And why are you just looking at that ten-year period of time?

A Because those are the ten years from 1996 when this proposed switch would have occurred to now.

Q To now. Right. But would the company in 2005 have recovered the full $60 million necessary to do the capital

upgrades in order to do this blend onsite by 2005?
A No. They would still have an outstanding amount to be recovered in the future.
Q And at the end of this ten-year period of time what does your 51 -- you called it a negative $51 million. What does that represent just at that end of the period of time?
A The negative $51 million represents the amount of additional money the company would have paid for coal, transportation, additional operating and maintenance expenses, and the portion of the capital that they had recovered to date.
Q And so does that represent a fuel savings or a cost to the customer versus what the company actually did over that 1996 to 2005 time period?
A That represents an additional cost to the customer over what the company actually did during that time period.
Q Okay. So it would -- and at the end of this 2005 period has the company recovered the full amount of that capital investment of $60 million necessary to even burn the 50/50 blend on site?
A No. It would still have a residual amount of capital left to be recovered.
MR. WALLS: I hope that helps. That's the best I can do.
CHAIRMAN EDGAR: Commissioner Carter.
COMMISSIONER CARTER: It's really pretty much the

same answer he had given me. I'm from South Georgia and I like, you know, we like things real simple there.

One, we talked about the cost to improve the infrastructure of the plant to burn this, this coal. Two, we talked about the additional operating and maintenance costs for going through the conversion. And today Mr. Heller is talking about transportation and the cost of the coal. So I'm -- you know, I understand the cost to upgrade the plant to work and make this conversion and burn this type of coal. I understand what it would cost in the additional maintenance and all like that.

Today we're talking about getting the fuel to the plant. That's different to me, that's different to me than what it would cost to upgrade the plant, what it would cost to maintain the plant during the process. Now we're talking about -- because yesterday that was just the plant itself. Now we're talking about what it would cost to get the fuel to the plant and what it would cost -- do you understand what I'm saying? It's not apples and grapefruit, not from my standpoint. Maybe apples and kumquats. But the point of the matter is, you said is -- Mr. Hatt said -- I can read my notes. He said $60 million to upgrade CR4 and CR5. That's to upgrade the facilities, the plants themselves in order to burn this blend. He said $2 million dollars annually in ongoing operating and maintenance costs for that for CR4 and CR5. And in my rough guestimate, going back ten years at $2 million a year, that's where I came up with the $20 million to add on top of that $60 million, so I got $80 million. Today I hear discussion on $50 million. In looking at your exhibits, you say $51 million. But I'm trying to say -- what I'm trying to get in my mind is that is this $80 million operational and maintenance and infrastructure improvement to the plant plus $50 million for the fuel or is it all a wash? Do you understand? I mean, do you understand what I'm asking you?

THE WITNESS: I do. I understand exactly what you're asking. I'm trying to put this in terms that answer it.

The -- what -- my negative $50 million or $51 million is not just the coal and not just the transportation. You could -- I could look at the cost of buying coal as Progress Energy did, whether it was imports or Central Appalachian coal, delivering it to the plant, and let's say that cost, I'll use dollars per million Btu because the -- let's say it costs $40 a ton to do that for imported coal or for Central Appalachian -- for Powder River Basin coal.

Now if I add up the cost of the coal and the transportation for Central Appalachian coal and if it costs $40 a ton for the Powder River Basin coal and it costs me $50 a ton for the Central Appalachian coal, then at first blush it looks like the Powder River Basin coal is going to be cheaper, $40 for the Powder River Basin coal, $50 for the Central

Appalachian coal.

In order to -- if I just do the math on that basis, I miss several things I have to adjust for. One of them is the heating value of the Central Appalachian coal is much higher than the heating value of the Powder River Basin coal. So you need more tons of Powder River Basin coal to drive the generators.

COMMISSIONER CARTER: So there's a cost for that.

THE WITNESS: There's a cost there. That's right.

COMMISSIONER CARTER: Okay. So add that to your, add that to your equation.

THE WITNESS: Right.

COMMISSIONER CARTER: Because where we go to the bottom line when we get -- I just want to let you know upfront when we get to the bottom line I want to know the bottom line for the cost of fuel excluding -- I've already separated that other cost out. I don't want to talk about that. I don't want to talk about what it costs to improve the plant, I don't want to talk about the $2 million maintenance. I just want to talk about the cost of the coal itself, the transportation of the coal. Now you told me because there's a different Btu level, so you're going to need more of it. So add that into the equation and tell me exactly what it would cost for the coal. I think that's in your testimony.

Thank for your indulgence, Madam Chairman.

CHAIRMAN EDGAR: Take your time.

COMMISSIONER CARTER: I just need a minute here.

In your testimony, you're a consultant and you provide consultant 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; right?

THE WITNESS: Yes, sir.

COMMISSIONER CARTER: Okay. So what I want to know is what is the energy and transportation, energy and transportation market costs and compliance for this case here --

THE WITNESS: I can --

COMMISSIONER CARTER: -- based upon what's presented to us?

THE WITNESS: I can answer your question with Exhibits JNH-6 and JNH-7.

COMMISSIONER CARTER: Okay.

THE WITNESS: If you can -- you may have to tear them apart, but I can --

COMMISSIONER CARTER: All right. That will be fun to tear it apart. Okay.

THE WITNESS: Okay. If you look on Exhibit JNH-6.

COMMISSIONER CARTER: Okay.

THE WITNESS: Column 10.

COMMISSIONER CARTER: Okay.

THE WITNESS: For 1996.

COMMISSIONER CARTER: 2.23.

THE WITNESS: 2.23. That's dollars per million Btu. The reason I'm doing that instead of dollars per ton is to adjust for this heating value problem we were talking about.

COMMISSIONER CARTER: Okay.

THE WITNESS: Okay. If you take a look at Exhibit JNH-7 and you go to Column 4.

COMMISSIONER CARTER: Okay. 2.16.

THE WITNESS: You'll see the delivered price for Central Appalachian coal in 1996 was $2.16.

COMMISSIONER CARTER: Okay.

THE WITNESS: And the evaluated price for Powder River Basin coal in 1996 is $2.23 a ton. That has, involves -- that does not involve Mr. Hatt's capital costs. His capital costs are separate. His $60 million is a separate calculation.

COMMISSIONER CARTER: Okay. Can you bottom line this for me or ballpark it?

THE WITNESS: I'm going to do something really crude, and since I have to do this in real time, I --

COMMISSIONER CARTER: Just give me a guestimate.

THE WITNESS: Take the $51.3 million --

COMMISSIONER CARTER: Okay.

THE WITNESS: -- number that I've got. I have to subtract from that the $20 million, some portion of the $20 million because I think it's net present valued. So if I were to subtract --

COMMISSIONER CARTER: That leaves us $31 million.

THE WITNESS: 15, that would give me $31 million. If they spent, you know, $60 million on capital costs and they may have recovered a third of that, you know, that's 20. That still says without considering any of the capital --

COMMISSIONER CARTER: So you add 40 to the 31 then; right?

THE WITNESS: From the 31 you would -- from the 31 you subtract the 20 that is already in here. In other words, the 20 -- if they recovered a third of the $60 million they spent -- in other words, they spent $60 million over -- let's say it was going to be recovered over 30 years, this has lasted ten years, so a third of the 60 that they recovered would be $20 million. You didn't want me to count the capital portion of that.

COMMISSIONER CARTER: So that leaves you $40 million; right?

THE WITNESS: So it's going to be somewhere in the -- it would be -- there would still be -- it would still be a negative number. In other words, the cost of the Central Appalachian -- the PRB coal would still be greater than the

Central Appalachian coal.

COMMISSIONER CARTER: But just on that straight line that we've been going on, that leaves us about $40 million; is that right?

THE WITNESS: The negative number, I think, would be more like $20 million, something like that. But I would really prefer -- this isn't the proper way to do it. I would prefer not to have done what we just did, but to help you in terms of understanding it.

COMMISSIONER CARTER: Okay. Thank you, Madam Chairman. Thank you, Mr. Heller.

THE WITNESS: Yes, sir.

CHAIRMAN EDGAR: Okay. Exhibits.

MR. WALLS: I'm sorry. I just had one minor redirect.

CHAIRMAN EDGAR: Oh, I'm sorry. I thought you had finished. Go finish your redirect.

COMMISSIONER CARTER: You were supposed to be helping me, by the way.

MR. WALLS: I am just a lawyer, so.

CONTINUED REDIRECT EXAMINATION

BY MR. WALLS:

Q Mr. Heller, I believe you were asked some questions by Mr. McWhirter about your JNH-6 in respect to the market proxy and which columns included the market proxy. Do you recall that?

A Yes.

Q And are you on JNH-6?

A I am.

Q Okay. And when you referred to Column 5 as including, I think you said the market proxy. Does that include additional costs besides the market proxy?

A Yes, it does. I included in there the blending fee along with the market proxy for the IMT.

Q And where did you get the blending costs from?

A The blending cost we've included in there was from Mr. Sansom's estimate of what the cost would be of blending at Crystal River.

Q In this calculation, the blending costs, did you look at Mr. Hatt's --

A I'm sorry. What's in Column 5 is the, actually the recovery of what the Commissioner was asking me about regarding the $2 million a year that is in Mr. Hatt's analysis. That's actually in my Column 5.

Q And I believe you were asked a question by Mr. McGlothlin about the TECO rate being a proxy. Do you recall that?

A Yes, I do.

Q Did you use the TECO rate in your analysis between 1996 and 2003?

A Not at all.

Q Who did?

A Mr. Sansom did.

Q And was that a competitive rate?

A No. That's a market proxy. And Mr. Sansom notes that it was far in excess of market, but it's what he uses for his comparison.

MR. WALLS: No further questions.

We would at this time move Mr. Heller's exhibits in evidence, Exhibits 79 through 87, which I believe includes his direct and rebuttal exhibits.

CHAIRMAN EDGAR: Yes. That is my understanding. Exhibits 79 through 87 will be moved into evidence.

(Exhibits 79 through 87 marked for identification and admitted into the record.)

And then, Mr. McGlothlin, you have an exhibit.

MR. McGLOTHLIN: I move 225.

MR. WALLS: No objection.

CHAIRMAN EDGAR: Okay. Exhibit 225, which I have labeled Direct Testimony, J. Heller on behalf of FMPA, et al., 9/19/06, will be moved into the record as evidence.

(Exhibits 225 admitted into the record.)

The witness is excused.

MR. WALLS: May he be dismissed, please?

CHAIRMAN EDGAR: Yes, he may.

Let's take a short break to stretch, and then, Ms. Bennett, we will call your witness. We will come back at 25 after by the clock on the wall.

(Recess taken.)

CHAIRMAN EDGAR: Okay. We will come back from break and go back on the record. And, Ms. Bennett, your witness.

MS. BENNETT: We call Mr. Bernard Windham.

MR. BURGESS: Madam Chairman, while Mr. Windham is coming to the witness stand, I would like to ask a request of the Chair. I've spoken to the parties about this. We have one witness who has pressing travel plans, Dan Lawton, and I would ask that we move him in the order of our witnesses when we get to our portion of the case, if we can move Mr. Lawton to first on our witness list.

CHAIRMAN EDGAR: Okay. So we will take up Mr. Windham, and then I would expect that we would call Mr. Stewart. And then as we move into the rebuttal, we'll begin with Mr. Lawton.

MR. BURGESS: Thank you, Madam Chairman.

CHAIRMAN EDGAR: Thank you.

Ms. Bennett, has your witness been sworn?

MR. YOUNG: Yes.

CHAIRMAN EDGAR: Oh, sorry, Mr. Young.

MR. YOUNG: Not a problem, Madam Chair.

BERNARD M. WINDHAM

was called as a witness on behalf of the Staff of the Florida Public Service Commission and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. YOUNG:

Q Mr. Windham, please state your full name and business address for the record.

A Bernard M. Windham, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee 32399.

Q Have you been sworn, Mr. Windham?

A Yes.

Q Did you submit prefiled testimony in this proceeding consisting of 14 pages?

A Yes, I did.

Q Do you have any changes or additions to that testimony?

A No. No.

Q With regard to your testimony, if I were to ask you the same questions set forth in your testimony, would your answers be the same?

A Yes.

Q Are you sponsoring any exhibits with your testimony?

A Yes.

Q What are those exhibits?

A BW-2 through BW-11, and they're listed on Pages 2 and

3 of my testimony.

Q At this time, Madam Chairman, I'd ask that Mr. Windham's testimony be entered into the record as though read.

CHAIRMAN EDGAR: The prefiled testimony will be entered into the record as though read.

MR. YOUNG: Thank you.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

TESTIMONY OF BERNARD M. WINDHAM

DOCKET NO. 060658-EI

February 14, 2007

Q. Please state your name and business address.

A. My name is Bernard M. Windham. My business address is Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Fl 32399.

Q. By whom are you employed and in what capacity?

A. I am employed by the Florida Public Service Commission (PSC or Commission) as an Engineering Specialist III since 1982.

Q. Have you previously testified before the Commission?

A. Yes. I have testified in several dockets before the Commission including Docket No. 890833-EU, which was an investigation into the cost effectiveness of undergrounding electric utility lines.

Q. What are your duties and responsibilities?

A. I perform analyses of utility fuel and fuel transportation costs. I maintain a data base containing fuel cost data as reported by investor-owned electric utilities, and I also maintain a data base on quality filings. I assist in preparing the Commissioners for fuel adjustment hearings by issuing reports, and recommendations. I draft discovery requests for the fuel adjustment proceedings, and I review coal contracts and coal procurement documents filed in response to discovery requests. I also provide engineering and statistical analysis support to Electric Reliability and Cost Recovery Section staff as required.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide basic information related to the delivered prices and tonnages of coal procured by Progress Energy Florida, Inc. (PEF), and by several comparable utilities including JEA, Gulf Power Company, Mississippi Power Company, Alabama Power, and Alabama Electric Power during the time period of 1996 to 2005.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit BW-1 is omitted.

Exhibit BW-2, entitled Foreign Compliance Coal Purchased in Tons, is a summary of how much foreign coal was used by the listed companies during 1994-2005.

Exhibit BW-3, entitled Summary of Federal Energy Regulatory Commission (FERC) 423 Delivered Price Information, is a summary of data compiled in BW-9 from the FERC Form 423 which provides a comparison of PEF's prices for bituminous coal purchased to the median price of other coal purchased from South America. The final column shows the percent differential between the two prices.

Exhibit BW-4, entitled Comparison of Delivered Cost of Colorado Bituminous Coal to Delivered Price of Central Appalachian (CAPP) Coal for PEF, which provides a comparison of the prices paid by PEF for bituminous coal to prices paid by other southeastern utilities for coal purchased from Colorado.

Exhibit BW-5 is a copy of FERC 423 Form Definitions, Codes, and Sources.

Exhibit BW-6, entitled Breakout of Coal Purchased for Crystal River 4 and Crystal River 5 By Contract Type, which identifies PEF's contract coal purchase volumes and PEF spot coal purchase volumes for the years 1996 to 2004.

Exhibit BW-7, entitled PSC 423 Forms for Gulf Power Company (December 1999 and March 2004) and for Progress Energy Florida, Inc. (October 2002) shows the cost of the short haul trip between terminals near the mouth of the Mississippi River and the utilities' generating facilities.

Exhibit BW-8, entitled Columbia to Gulf Coal Freight Rates, US Army Corp of Engineers, shows the cost of delivery between South America and terminals at the mouth of the Mississippi River as reported by the Army Corp of Engineers.

Exhibit BW-9, entitled Excerpted Coal Delivered Price Information from FERC 423 Data Base, is information, excerpted from the FERC data base, used to prepare BW-3 and BW-4.

Exhibit BW-10 is a copy of PEF's Response to Staff's Sixth Set of Interrogatories, Number 91, Docket No. 040001-EI.

Exhibit BW-11 is a copy of PEF's Response to Staff's First Set of Interrogatories, No. 1, Docket No. 060001-EI.

Q. What are the data sources that you used to prepare your testimony and exhibits?

A. PSC staff maintains data bases with monthly coal prices and fuel costs. The data bases we maintain include:

-PSC A-Schedule data base,

-PSC Form 423 data base,

-FERC Form 423 database,

-coal price data based on monthly coal prices from various coal regions from the coal industry publication, U.S. Coal Review.

Q. What kinds of information are included in these data bases?

A. The PSC A-Schedules and PSC Form 423 Schedules are filed in the fuel docket each month by each investor-owned electric utility. The FERC Form 423 data base has information on all coal purchased and shipped to all U.S. utilities including delivered price information in cents per million BTUs. The PSC Form 423 data base has similar information, with more detail on transportation costs. The FERC Form 423 database is taken directly from the FERC web site, where it is posted after being filed with FERC by all investor owned electric utilities.

Q. Please provide a brief summary of your testimony.

A. The delivered price information for all U.S. utilities reported to FERC, as summarized in Exhibit BW-3, appears to show that during the time period of 1996 to 2005, Progress Fuels Corporation (PFC), on behalf of PEF, often did not purchase the lowest price coal that met PEF's coal specifications for Crystal River Unit 4 (CR4) and Crystal River Unit 5 (CR5). Other southeastern coastal utilities that use compliance coal have purchased large amounts of foreign low sulfur compliance coal that is similar to the Central Appalachian (CAPP) coal that PEF has primarily used during most of the period under consideration, while PEF has only purchased significant levels of such coal for use since 2003. [Exhibit BW-2]. During the time period of 1996 through 2005, the median delivered price of foreign low sulfur compliance coal to southeastern coastal utilities has been between 10 to 50 percent less than the delivered price of the CAPP coal or synfuel utilized by PEF.

Q. What does Exhibit BW-3 represent?

A. Exhibit BW-3 is a comparison of the median delivered price of bituminous South American coal paid by utility companies as compared to the price PEF paid for bituminous CAPP coal.

Q. What standard did you use to make this comparison found in BW-3?

A. I compared cents per million BTUs for each coal purchase.

Q. Why use cents per million BTUs to compare coal prices instead of dollars per ton?

A. It is the standard used by utility companies when comparing bid responses to Requests for Proposal (RFPs). The winning bid is determined by comparing the delivered prices of coal from the various mines and selecting bids which will result in the lowest overall cost for coal burned at the power plants. Typically, this comparison is done on the basis of cents per million BTUs. The use of cents per million BTUs in comparing coal prices is to normalize the coal price taking into consideration the fact that different coals have different heat values as measured in BTUs per pound.

Q. In comparing the delivered price of foreign coal to the delivered price of domestic coal, did you compare the delivered price of coal to the plant sites?

A. No. I compared delivery prices to the International Marine Terminal (IMT) or to a comparable Gulf coast terminal.

Q. Why did you choose to compare delivered prices to the IMT rather than directly to the Crystal River Power Plant site?

A. Foreign coal is delivered by large ocean going vessels. Ocean vessels cannot enter Crystal River because of the shallow Gulf access to the plant. Typically, foreign coal bound for use at PEF's Crystal River Power Plant is routed through the IMT at the mouth of the Mississippi River, where the coal is transloaded onto ocean barges for shipment to Crystal River. Similarly, CAPP domestic waterborne coal for CR4 and CR5 has historically been shipped to the IMT for storage, blending, or transloading onto Gulf barges for shipment to Crystal River Power Plant. Until 2004, both foreign coal and domestic waterborne coal bound for the Crystal River Power Plant was routed through the IMT facility and had the same cross-Gulf delivery price. Thus, to determine whether foreign coal or domestic CAPP coal would have been more cost effective for CR4 and CR5, it is sufficient to compare the delivered price of foreign coal to a Gulf terminal to the delivered price of domestic coal or synfuel delivered to the IMT terminal. In recent years, some foreign coal has been received at the Alabama State Dock in Mobile rather than at the IMT, but the delivered price of South American coal is similar for these terminals.

Q. You previously testified that BW-3 is a summary. What information does it summarize?

A. The delivered price of coal shipments reported by the utilities to FERC on the FERC Form 423 is used for comparison in this exhibit. PEF reports the prices for all waterborne domestic coal to the IMT, and also reports the delivered price of all U.S. waterborne coal for CR4 and CR5 to the IMT (or another Gulf coast terminal) to FERC. Thus, the delivered price reported to FERC of foreign coal through a Gulf terminal by other utilities can be compared to the delivered price of domestic CAPP coal or synfuel reported by PEF to FERC to determine the most cost effective option. [BW-9}.

Q. Is the information reported to FERC and published in its database on its website for most coastal utilities comparable to the data reported by PEF to FERC for shipments of either U.S. or foreign coal to the Crystal River Facility?

A. No. In order to make it directly comparable, we must deduct shipping costs for the short haul leg from the Gulf coast terminal used by the other utilities to their plants. The data reported to FERC by all utilities is the delivered price to the utility facility in comparable cents per million BTU units, along with information on the coal quality. The data reported to FERC by PEF is generally to the coal terminals near the mouth of the Mississippi River for storage and blending of coal received from either waterborne U.S. coal or foreign coal sources. Thus the information reported by PEF to FERC is the delivered price of coal from either waterborne or foreign coal to the IMT.

Q. How did you make these prices directly comparable?

A. Delivery costs for coal shipped from South America by ocean vessel to other Gulf Coast coal terminals or utility facilities are roughly equivalent to the delivery cost of coal shipped to the IMT for PEF. For example, JEA has a coal terminal at its Jacksonville St. John's Power Park facility with a trip distance that is very similar and shipping cost very similar to the trip to the IMT from South America. [See EXH BW-8].

A few other utilities along the Atlantic seaboard have similar waterborne coal terminals for their plants, albeit longer shipping distances for South American coal compared to IMT deliveries (thus, higher transportation costs). Several southeastern utilities such as Gulf Power Company, Alabama Electric Cooperative Inc., Alabama Power Company, and Mississippi Power Company ship coal to a coal terminal such as the Alabama State Dock in Mobile, and then transfer the coal to river barges for transport to their generating plants. For all of these utilities with the exception of PEF, the FERC reported data is the delivered price of the coal to their facilities, including the river barge trips.

The full delivered cost to each purchasing utility's plant, with the exception of PEF, is what is found in Exhibits BW-3, BW-4, and BW-9. As I testified earlier, the delivered cost to PEF is not to its plant, but to the IMT. A utility's transportation cost for coal shipped to a coal terminal on the Gulf coast like Alabama State Dock is roughly the same as what PEF's transportation costs to the IMT would be. The coal companies often give the buyer its choice of terminals. Each detail sheet in Exhibit BW-3 notes that a short haul leg is also included in the FERC 423 reported cost for these utilities and provides information on the approximate range of such cost. To more accurately compare the cost of delivered coal, it is beneficial to remove the cost of the short haul leg reported by utilities that use the South American coal option.

Gulf Power reports both the coal transportation cost to the Mobile coal terminal and the additional intercoastal river barge cost on its PSC 423 forms [Exhibit BW-7]. Likewise segmented transportation cost for PEF and other Florida utilities for each coal shipment are reported in the PSC 423 forms, though PEF files its form as confidential for 2 years. Most of the PSC 423 forms for PEF for 1996-2005 are now declassified. Examples of these costs for Gulf Power and PEF are provided in Exhibit BW-7. The costs of river shipments of coal for other coastal utilities that use the Mobile terminal are similar to the costs of shipments of coal for Gulf Power river barge trips. Additional information from the U.S. Energy Information Agency and from a survey of ocean shipping cost by the U.S. Corps of Engineers during this period for use in further refining comparisons is provided in Exhibit BW-8.

Q. Can you explain who Progress Fuel Corporation (PFC) is and how it is involved with fuel procurement for PEF?

A. PFC is an affiliate company of PEF that has operated under a contract with PEF to procure coal for PEF. PFC was responsible for the procurement and transportation of PEF coal from 1996-2005.

Q. What type of coal was being sought by PEF during the period 1996 to 2005, and what type of bids did PEF receive?

A. Since the CR4 and CR5 units do not have scrubbers, the type of coal sought and procured was low sulfur compliance grade coal. The specifications are contained in the direct testimony of Donna M. Davis, DMD-3, page 3. U.S. mines with such bituminous coal are typically in Central Appalachia or in the western U.S. There are also some mines in foreign countries such as Columbia and Venezuela that meet the PEF coal specifications for low sulfur compliance coal. There is also low sulfur sub-bituminous coal available from the Powder River Basin which meets the coal specifications used in some of the RFPs issued by PFC.

Q. Has most of the low sulfur coal purchased by other southeastern coastal utilities since 1996 met PEF coal specifications for CR4 and CR5?

A. Yes. There have been large quantities of low sulfur compliance coal available from countries such as Columbia and Venezuela that have been utilized by other coastal utilities since the 1980s. [EXH BW-2] PEF has purchased such coal only occasionally since the late 1980s, but has used much more of this foreign compliance coal since 2003.

Q. Over the period 1996 to 2005, has PFC on behalf of PEF generally purchased the lowest price compliance coal available that meets the specifications for CR4 and CR5?

A. No. The delivered price information for U.S. utilities in Exhibit BW-9, as summarized in Exhibit BW-3, shows that PFC has often not purchased the lowest price coal that meets PEF coal specifications. Other southeastern coastal utilities that use compliance coal have purchased large amounts of foreign low sulfur compliance coal that is similar to the CAPP coal that PEF has primarily used during most of the period between 1996 and 2005. PEF has purchased significant levels of such coal only since 2003. During most years from 1996 through 2005, the delivered price of foreign low sulfur compliance coal to southeastern coastal utilities has been significantly less than the delivered price of the CAPP coal or synfuel purchased by PEF. This can be confirmed by comparing the delivered prices of the CAPP coal used by PEF to the delivered price of low sulfur foreign compliance coal that meets the PEF coal specification requirements on a monthly basis throughout most of the period prior to 2004. During the period of 1996 to 2005, the average price of delivered PEF coal for CR4 and CR5, delivered to the IMT transfer facility at the mouth of the Mississippi River, was between 10 to 50 percent higher than the delivered price paid by southeastern coastal utilities for South American coal delivered in ocean vessels to a comparable coal terminal. [See Exhibit BW-3,and BW-9].

Q. When does it appear that coastal utilities began using foreign compliance grade coal as a cost effective alternative?

A. In 1994 this is observable from readily available information such as the FERC 423 data base on their web site in 1994. JEA, Gulf Power Company, and Tampa Electric Company, along with some other coastal utilities, used significant amounts of foreign coal from South America in 1994, and have generally continued to do so since that time. [See Exhibit BW-2]. PEF received 84,374 tons of foreign coal in 1994 at the IMT terminal at an average price of 145.50 cents per million BTUs. PEF shipped 1,335,700 tons of coal or synfuel from U.S. Region 8 in 1994 with an average price of 177.13 cents per million BTUs, but did not begin to use levels comparable to other southeastern coastal utilities until 2004. Twelve coastal utilities received 4,879,568 tons of low sulfur compliance coal from South America in 1994. The median price for roughly comparable shipments in large ocean vessels to a U.S. coastal coal terminal was about 145.50 cents per million BTUs. The delivered price for coal from U.S. Region 8 shipped to the IMT terminal in New Orleans for PEF was 31.63 cents/MMBTU or 21.7 percent higher than the cost of foreign compliance coal shipped to roughly comparable coastal coal terminals. [For details on comparisons for 1994 and 1995, see Exhibit BW-3].

Q. Has PEF always chosen the lowest cost U.S. coal that meets PEF fuel specifications?

A. No. From the FERC 423 delivered price data and previous staff discovery in this matter, it appears that other U.S. bituminous coal that was not purchased was available at prices below the price paid by PEF for fuel for CR4 and CR5. For example, a lower bid price for Colorado bituminous coal was received by PEF for a 2004 coal RFP than the bid actually accepted. Other utilities in the southeast along the coast using Colorado bituminous coal in 2004 and 2005 had a lower delivered cost than the PEF delivered cost for CAPP coal. [See Exhibit BW-4 and Exh BW-11].

Q. Under the assumption that no Powder River Basin coal should have been burned at CR4 and CR5, how much foreign coal could have been purchased for CR4 and CR5 from 1996 to 2005?

A. Approximately 1 million tons per year of foreign low sulfur compliance coal would have been possible to purchase for CR4 and CR5. Exhibit BW-6 gives a breakout of coal purchased for CR4 and CR5 by contract type for the years 1996 to 2004. On average over that period, 36.4 percent of the coal purchased for CR4 and CR5 was spot coal, amounting to an average of over 1 million tons per year. During most of this period, the coal procurement and transportation for the coal utilized by PEF was provided by affiliates wholly or partially owned by PEF's parent company. There were 3 year contracts with affiliate companies for river transportation, terminal transloading, and cross-Gulf shipping. The minimum volume for the most recent river transportation contract is 500,000 tons per year. The MEMCO contract (a contract between PFC and MEMCO for shipping PEF's coal by river) covering August 2001 to July 2004 had a minimum volume of 1.26 million tons. If the minimum was not met in a year, the difference could either be made up in the next year at the same rate or a penalty of $2 per ton would be required. Using the following formula [Y (cents/million BTU) = X ($/ton) times .05 times 1,000,000/ Z (BTU/pound)] for converting $2 dollars per ton to cents per million BTUs for coal with a heat value of 12,100 BTU/pound, one gets 8.26 cents per million BTUs. For the period of 1996 to 2005 had PEF decided to buy 1 million tons of foreign compliance coal for CR4 and CR5, any limits imposed by existing transportation contracts would have been relatively short lived before adjustments in transportation contract minimums could have been fulfilled. Since foreign coal purchases for CR4 and CR5 would be through a Gulf terminal, such purchases could only affect the river transportation contract. From the coal delivery breakout for CR4 and CR5, it would appear that at least 500,000 tons of foreign compliance coal could have been purchased for any year without a penalty and with an average of about 1 million tons per year possible for most years. [Exhibit BW-6].

For commodity contracts, PEF primarily had 2 long term contracts during this period with Massey Coal Company and Powell Mountain expiring in the spring of 2002. The Powell Mountain coal was primarily delivered by rail, so is not relevant to the waterborne shipping issue. Each had a minimum of about 850,000 tons, but the contracts typically had a reopener about every 18 months at which time changes in the terms could be made by either party with cause. The Massey contract (a coal contract between PFC and Massey Coal company) had a clause that periodically allowed either buyer or seller to make changes in the contract with 6 months notice. Any limits in purchase of foreign coal due to coal contracts appear to be of minor short term nature and similar to that related to transportation contracts.

Q. You testified that during the time period of 1996-2005 PEF also took shipments of synfuel. Is the delivered price of synfuel directly comparable to the bid for delivered price of bituminous coal received in the coal RFPs?

A. No. An additional $2/ton (for instance it would equate to an additional 8.26 cents per million BTUs for coal with a heat value of 12,100 BTU/pound) could be added to the cost of synfuel to make it comparable to bituminous coal of a similar heat rate.

Q. Why isn't the delivered price of synfuel directly comparable to the delivered price of bituminous coal?

A. In most cases synfuel is bituminous coal that has been processed and sprayed with an additive. But synfuel is not directly comparable in quality to coal, since synfuel is sticky and clogs up transportation equipment, unloading equipment, and boiler chutes, and has effects on the boiler operations. Synfuel might also have decreased BTUs available but this is taken into account in the cents per million BTUs calculation. Because of these problems, synfuel has typically been blended with coal before burning which is additional cost. These problems are significant and have been described in PEF's response to Staff's Sixth Set of Interrogatories, No. 91, Docket No. 040001-EI, [Exhibit BW-10] Thus synfuel has additional quality and operation and maintenance expenses that must be taken into account when comparing the price of synfuel to bituminous coal.

Q. How did you determine that $2/ton should be added to the cost of synfuel to make it comparable to bituminous coal?

A. The market price discount for the differential price of coal shipped as synfuel that is typical for Florida utilities is $2/ton. Since this is the price the market has determined is the differential price that utilities commonly will accept synfuel instead of coal, this appears to be a reasonable estimate of the quality and operational cost differential between coal and synfuel.

Q. Does this conclude your testimony?

A. Yes.

BY MR. YOUNG:

Q Mr. Windham, have you prepared a summary of your testimony?

A Yes, I have.

Q Would you please provide us with that summary at this time?

A Good morning, Commissioners. The purpose of my testimony is to, is to add information from staff databases to provide a comprehensive set of information to address the coal procurement practices of PEF as it relates to foreign and western bituminous coal. Information from staff discovery and databases maintained to monitor fuel clause expenses indicated that for most years from 1996 to 2005 South American or western bituminous coal appeared to be the most cost-effective options available to PEF. During these years other southeastern and coastal utilities were using increasing amounts of such coal procured at prices virtually always less than the prices of the CAPP, the Central Appalachian coal or synfuel procured for PEF.

Historically, waterborne delivered coal procured for PEF, both Central Appalachian coal and foreign coal, has been received and processed at the IMT coal terminal on the Gulf Coast. Each month all major utilities in the U.S. report delivered price and quality information to the, to the Federal Energy Regulatory Commission, which is included in the FERC 423 database. All of the data reported each month to FERC by PEF had the delivered price of coal to the IMT terminal.

In recent years, some foreign coal procured for PEF is to another Gulf Coast terminal in Mobile, which is also used by several other southeastern utilities in my comparison. Since most other utilities' data reported to FERC is the delivered price to their plant, most of the other utilities' delivered price includes the cost of an additional transportation leg to get the coal from the receiving terminal to the plant. The price for foreign coal most comparable to the price of procuring foreign coal for PEF at the IMT or Mobile terminals is the price of the other utilities to the receiving coal terminal. The FERC reported prices for most other utilities listed in my, in my Exhibit BW-9 represent a conservative estimate of these delivered prices. Average delivered prices for the FERC data for each year were calculated for PEF and the other coastal utilities.

Some of the utilities, including my Exhibit BW-3 summary of average delivered price comparisons, have significantly higher additional transportation short-haul leg costs included. And outliers can significantly affect averages. Thus, for each year the median of the utility average delivered prices for the utilities using foreign coal was chosen as the most valid summary measure of the average delivered price for foreign coal. These are provided in BW-3 compared to the average delivered price of Central

Appalachian coal procured for PEF. Prices for contract coal can be more or less than the price for spot coal depending on market conditions; thus, the average delivered price of foreign coal and PEF CAPP coal were calculated separately for contract versus spot for each year. These are shown in the yearly summaries in BW-3. The medians for each year for both spot and contract coal are easily calculated from the summary data in BW-3. That concludes my summary.

MR. YOUNG: Madam Chairman, at this time we'd tender Mr. Windham for cross.

CHAIRMAN EDGAR: Thank you.

Mr. Walls.

MR. WALLS: Yes. Thank you.

CROSS EXAMINATION

BY MR. WALLS:

Q Good morning, Mr. Windham.

A Good morning.

Q I understand you're testifying as an expert in this proceeding; correct?

A Correct.

Q And as I understand from your testimony, you're relying on your experience and responsibilities as an engineering specialist for staff; right?

A Yes.

Q And I understand you've worked in the fuels department of staff for ten years; right?

A Approximately.

Q I further understand that you monitor the fuel information filed by the utilities in the fuel docket each year, you compile and maintain databases of the PSC and FERC forms that include delivered fuel prices including coal, and you review coal RFPs and contracts; is that correct?

A I've been doing the database part for most of the ten years, the database part especially with respect to the A Schedules. I've also had other responsibilities. I only started looking at coal, coal issues and the, the contracts and RFPs and that kind of thing late in 2001 and mostly starting in 2002.

Q So the answer to my question would be, yes, that's what you do, right, currently?

A Yes, that's what I currently do.

Q Now you also testify at Page 1 of your direct testimony that you assist the Commissioners in preparing for fuel adjustment hearings by issuing reports and recommendations; correct?

A Yes.

Q You indicated that you have drafted discovery requests for the fuel adjustment hearings; right?

A Yes.

Q And that's part of your job, right, to draft discovery requests for fuel adjustment proceedings?

A Yes, it is.

Q And the way a utility goes about procuring coal is through requests for proposals for contracts or spot contracts using vendor lists and other information; correct?

A Yes.

Q And you understand that you need to send a discovery request to the utility to get the RFPs and the RFP responses in the contracts; right?

A Yes.

Q And you could have asked for those documents in any of the fuel proceedings; correct?

A Yes.

Q And you would agree with me that it was your job to review coal contracts and coal procurement documents for prudence issues; correct?

A Starting in 2002.

Q And that was your job to review them for prudence issues; right?

A Well, to review for prudence and various aspects related to the recovery of, of fuel costs.

Q And one purpose for you to compile and maintain PSC schedules and FERC form databases is to use them to see if the utility was reasonable and prudent in coal procurement decisions; right?

A That's one reason.

Q And you would agree with me that the purpose of your job to issue reports and make recommendations for Commissioners in fuel adjustment hearings was so the Commission could determine whether coal prices the utility incurred were reasonable and prudent; right?

A Yes.

Q And you would agree that the utility, I'm sorry, the Commission ultimately has the decision on whether the utility acted reasonably or prudently; right?

A Yes.

Q But the Commission will rely on staff, and that's your job; right?

A That's right.

Q Now I want to turn to your Exhibit BW-3 to your testimony. Are you there?

A Yes.

Q In your Exhibit BW-3 to your testimony you're comparing the average contract and spot delivered prices for PEF to the median price of foreign coal purchases for other utilities as reported on the FERC Form 423 for the period 1994 to 2005; right?

A As I stated in my summary, what I did was -- if you look at the other, the other pages of my BW-3, the various utilities' spot and, spot and contract coal tonnages and delivered price, average delivered price were calculated for all utilities. So I calculated the average delivered price for all utilities and, and also for Progress. And if one wants to, you can compare the average delivered price of any utility to that of, of Progress.

But for a summary measure, due to the fact that, that these average delivered price numbers for the various utilities, some of these utilities have, are considerably further away like as in New England and some of them have additional short-haul costs by, by barge or rail or trucking, and so that some of them have fairly high short-haul costs and that Progress doesn't have any. So due to these various differences in the utilities, some, some of those utilities would be outliers due to the additional cost.

So that being the case, I decided that the most reasonable and accurate summary measure for the average delivered prices of the foreign coal for any given year would be to take the median of the average delivered prices of the various utilities.

Q Okay. Mr. Windham, if we could look at BW-3, the first column is entitled Year; is that correct?

A I'm sorry. Looking at BW-3?

Q Yes.

A Which page?

Q The very first page. I'm sorry. Page 1 of 13.

A Okay. Yes.
Q The first column is entitled Year.
A Yes.
Q The second column is entitled PEF/U.S. CAPP Average; correct?
A Yes.
Q The second column, I mean, third column is entitled South American Median; correct?
A Yes. That's the median of average delivered prices of the various utilities.
Q And then you calculated the difference from that; right?
A Yes.
Q Mr. Windham, it's also true in this hearing that you're not testifying that PEF actually made any imprudent coal purchases; correct?
A When I did my testimony, I was -- for the most part, I had noticed that the record was not complete with respect to purchases of the various kinds of coal options that were available to PEF. And so the main purpose of my testimony was to put in the record the prices that all the different utilities that might be comparable to PEF had reported to FERC as far as the delivered price of their various coal purchases. And so my data that I put in the record was for that purpose, was for looking at what options were out there and what were

the most cost-effective options to look at.

As I noted in my, in my deposition, there was another part. The other part that I did not look at in my testimony was the discovery and further looking at the reason that Progress did not purchase what appeared to be the most cost-effective options. And so that, that part I left undone until, until discovery had been accomplished.

Q Mr. Windham, if you could turn to Page 68 of your deposition, which I'll put up for you, 68, Lines 2 through 11, where I asked you the following question, you gave the following answer:

Question, "Is that the first year that you say that PEF made an imprudent coal purchase?"

Answer, "I haven't said that PEF made an imprudent coal purchase. What I've said is that it was commonly the case that other coastal utilities were procuring coal mostly from foreign sources that was compliance grade coal that was cheaper than the coal that was being procured in larger part by PEF. There are other issues involved in prudence other than just the fact that one can procure something at a lower price."

Is that an accurate statement?

A That's right.

Q Now you understand that the issue in this proceeding is whether PEF acted reasonably or prudently in its coal procurement practices for CR4 and 5 during the years 1996 to

2005; right?

A Yes.

Q And it's true that you have no opinion as to whether PEF acted reasonably or prudently or not in its coal practices from 1996 to 2005; right?

A I had no opinion when I wrote my testimony because I had not seen the discovery, the discovery that was being carried out on the issue of why Progress did not appear to have recovered the most, purchased the most cost-effective options.

Q And you also had no opinion at the time of your deposition; right?

A Yes, because the discovery had not been completed at that time.

Q And you certainly filed no report or recommendation regarding the foreign coals in your testimony for CR4 and 5 with the Commission in any prior fuel docket proceeding; correct?

A I'm sorry?

Q You certainly filed no report or recommendation regarding the foreign coals that you testify in your testimony in Exhibit BW-3 for CR4 and 5 with the Commission in any prior fuel docket proceeding; right?

A When I noticed -- when I started looking at, at the, the fuel procurement practices of, of the utilities that had affiliates like Progress and Tampa Electric, I noticed pretty quickly that I thought there were some problems. And with respect to Progress, what I, what I did in 2002 was to request that an audit be done of Progress Fuels to look at coal procurement and, and coal transportation practices. So the first thing I did in 2002 was to request an audit.

Q Mr. Windham, I asked you the following question, you gave the following answer in your deposition at Page 62, Lines 20 to 25, carrying over to Line 1 through 3 on Page 63:

Question, "Prior to filing your testimony in this docket have you ever prepared a report or recommendation to the Commission that addressed whether foreign bituminous coal could have been purchased cheaper than the coal that was purchased for CR4 and 5?"

Answer, "I don't remember such a report for CR4 and 5. I believe that I drafted a document that related to another utility."

Is that correct?

A That is true.

Q And as I understand, the information that you are providing this Commission in this proceeding is what you regard as factual information; correct?

A The information that I'm providing I do regard as factual information.

Q Well, let's turn to that factual information and look at it.

A Okay.

Q As I understand, what you did not include in your testimony or exhibits is any RFP request or response that PFC did for PEF for CR4 and 5; correct?

A I was aware that the RFPs were in the testimony of your witnesses which I had looked at, so I didn't include them in mine.

Q And you didn't include in your testimony or exhibits any actual spot offers or acceptances for coal for CR4 and 5 during the years 1996 to 2005; correct?

A I included in my, in my FERC data the results of the acceptances of spot and contract coal during that period.

Q But you didn't actually include any actual spot offers or acceptances for the coal during the years --

A No. And, again --

MR. YOUNG: Objection, asked and answered.

THE WITNESS: Well, I don't mind answering.

I again, I again was aware that the offers, the spot and contract offers were provided by your witnesses, which I had looked at. And so since they were, since they were provided by your witnesses, I did not bother to put them in mine.

BY MR. WALLS:

Q In fact, you can't point me to any place in your testimony or your exhibits where you make any reference to a

Progress Fuels Corporation RFP or spot offer or response or spot offer acceptance between 1996 and 2005; right?

MR. YOUNG: Objection, compound question.

MR. WALLS: Well, we can take them in pieces.

CHAIRMAN EDGAR: Let's try that.

BY MR. WALLS:

Q Mr. Windham, you cannot point me to any place in your testimony or your exhibits where you make reference to any PFC RFP in the responses to that RFP from 1996 to 2005; correct?

A That's correct. That was not the purpose of my testimony.

Q And you also can't point me to any place in your testimony or exhibits where you make any reference to any PFC spot offer and acceptance between 1996 and 2005; correct?

A That's correct.

Q And for all the other utilities that you compare PEF to in your testimony and exhibits, you haven't obtained from those utilities their RFPs or responses, their spot offers or spot responses in connection with the coal purchases identified in your exhibits; correct?

A That's correct.

Q What you do rely on is FERC Form 423 data for PEF and these other utilities; correct?

A That's correct. And I will mention that that's very similar to the FPSC 423 data that we work with here at the

Commission. It has the same data plus some additional details. And the FPSC 423 forms are, in fact, the main thing that we use in looking at issues like prudence and that kind of thing. So this is comparable, what I used is comparable to what we do in normal practice.

Q And you would agree with me that the FERC Form 423 data includes the cost of coal that has already been delivered; correct?

A Yes.

Q So when utilities prepare the FERC Form 423, they are reporting on coal procurements that have already occurred; right?

A That's correct.

Q And that's the same for the PSC schedules; right? They indicate coal actually delivered in prior months; right?

A Yes.

Q And the FERC Form 423 and the PSC schedule's data do not indicate whether a utility went out for an RFP and when it went out for an RFP; correct?

A That's correct.

Q And the FERC Form 423 data and the PSC schedules do not indicate when a spot offer was made and when it was accepted; correct?

A That's correct.

Q And the FERC Form 423 and PSC schedules do not indicate when a utility entered into a term or spot contract for the coal reported in the data; correct?

A That's correct. But spot contracts in general are usually less than six months.

Q And you would agree with me though that the spot prices that are reported in the FERC form data in the PSC schedules could have been months before and the term contracts a year or more before the delivered prices that are reported in those forms; correct?

A Correct.

Q And it's true that a spot offer and acceptance represents a market price at a point in time, and that price is not necessarily comparable to what might happen at another point in time even in the same year; right?

A That's correct.

Q So what you have and are relying on is delivered price information, but you would agree that you need to know more than the delivered price to determine whether there was some other coal that should have been bought; right?

A Yes. As I noted, one thing would be why, why the choices that were made were in fact made.

Q And that's because in prudence review there's something -- prudence review involves more than just what can be, what coal can be procured at the lower price; right?

A That's correct.

Q And you would agree that quality characteristics of coal such as the Btu value, sulfur content, ash qualities, moisture content are important considerations in making any coal procurement decision; right?

A That's correct. But just for example the Btu content is taken into account in the cents per million Btu calculation that is, that's given as the delivered price in the FERC data and in the FPSC 423 data -- well, in the FERC 423 data. And it's also what is commonly used by utilities in looking at which coal is the most cost-effective.

Q And you would agree with me that a utility needs to be flexible in its approach to RFPs and spot purchases for coals; right?

A Yes, within the Commission guidelines. The Commission has a procurement guideline, an order in that regard.

Q And you would also agree with me that a utility management must be able to exercise judgment on the balance between RFPs and spot purchases; correct?

A Again, subject to the Commission guidelines and the procurement order, which include the fact that they should procure most of it through long-term contracts that are, that use RFPs.

Q Turning to your analysis of foreign coal purchases in Exhibit BW-3, and as I understand --

A I'm sorry. Refer me where?

Q Back to BW-3, Mr. Windham. I'm sorry.

A Okay.

Q And what you did on one side of the column with respect to the PEF/U.S. CAPP average prices is you combined the average of the contract and spot price in that column; correct?

A Of a sort. When I submitted this, I was in the process -- well, I had, I had divided out -- I started, I started off with, with the data not broken out into contract and spot, and I decided it needed to be broken out into contract and spot to give further definition to what was going on with the procurement.

And like I said, if you look at the various yearly pages in BW-3, you will see that they are, in fact, broken out by spot and contract. But, but when I, when I calculated this particular table -- I intended, I intended to substitute a different table for this one that included the comparison by both spot and contract, and I had actually, I had actually done the medians at that time. But we had some problem, we had some major problems with producing my big, my big BW-9 and I had to redo that at the last minute. And due to that, I never got around to substituting the, the more complete version of the BW-3 summary.

Q Okay.

A So the version, the version I have is the, is the, on

Page 1 is the -- what it did, it took the, all of the coal for, for the utility and, and calculated an average, an average price.

Q Mr. Windham, my question --

A Which that would be the same as doing -- I'm sorry. That would be essentially the same as doing a weighted average of the spot and contract.

Q Mr. Windham, my question was looking at the column entitled PEF/U.S. CAPP average, what you have done is taken the average of PEF's contract and spot prices in each of those years from 1994 to 2005; correct?

A Well, like I said, what I did was take, I took all, all of the purchases and did a weighted average.

Q Mr. Windham, if I could refer you to your deposition, Page 75, Lines 14 to 18, the question was:

"So what you've done there for Progress Energy Fuels is you've taken the average of their contract and spot prices, correct, in each of those years from 1994 to 2005?"

Answer, "Yes."

A A weighted average. I'm sorry. Which is the same thing as the average of, of the whole, of all the data.

Q Mr. Windham, if you would turn to -- let's look at 1994, Page 2 of 13. Are you there?

A Page 94?

Q Yes. Page 2 of 13, the year 1994 in Exhibit BW-3.

A Oh, I'm sorry. Okay. Okay.

Q And what you can see there on the, in the middle of the document, do you see where you have a series of columns, tons on the left, price in the middle, utility on the right?

A Yes.

Q And you've broken out for these other utilities their prices from spot and contract; right?

A Yes. These are -- I'm sorry. Yes. These are average, average delivered price for spot and contract for each utility.

Q Right. And so what you have, for example, for JEA is you have their average spot price over that year, 1994.

A Yes. That's right.

Q And you have their average contract price broken out separately --

A Yes.

Q -- for that same year; correct?

A Yes.

Q And that's the same way you did it for every other utility other than PEF who bought import coal; correct?

A I'm sorry. Repeat that.

Q That's the same way you did it in this analysis for each year for every other utility except PEF; correct?

A I calculated the average delivered price for all utilities, for each utility just like I did for PEF.

Q Well, Mr. Windham, do we need to go back to your past statement in your deposition where you admitted that for Progress Energy Fuels you took the average of their contract and spot prices together from 1994 to 2005?

A The weighted average.

Q Yes.

A Which is the same thing. Yeah.

Q And you would agree with me that that comparison you did was not an apples-to-apples comparison; correct?

A All of my, all of my numbers for -- if you look, if you look -- well, anyway, the, all of my numbers are average, are average delivered prices. And you can compare the average delivered price of any utility to the average delivered price of Progress.

You will note that I have an average delivered price for Progress for both spot and contract, and I likewise do for the other utilities, and you can compare them apples to apples, spot to spot and contract to contract.

Q Mr. Windham, if you would look at your deposition, Page 80, Lines 2 to 5 where I asked you the question:

"Mr. Windham, it's not the same comparison. It's not an apples-to-apples comparison, is it?"

Answer, "It's not an exact comparison. I did this as a ballpark."

Is that accurate?

A I'm sorry. Which page?

Q That's an accurate statement, isn't it?

A The -- like I said, the numbers on the page are, I have for both Progress and for the other utilities, I have average delivered prices. You can compare them, for any utility you can compare the average delivered price for spot and contract or, or for the total for any utility and for -- for any of the other utilities and likewise for the, for Progress.

Q Mr. Windham, in this analysis that you did comparing Progress Fuels' average CAPP and spot and contract prices to the South American median price of other utilities, what you purported to compare was PEF purchases to foreign bituminous coal purchases by other southeastern coastal utilities; correct?

A I'm sorry. Repeat.

Q What you purported to compare in this analysis was PEF purchases for CR4 and 5 to foreign bituminous coal purchases by other southeastern coastal utilities; correct?

A Yes.

Q But if you look at Exhibit BW-3 again, Page 1 of -- well, let's go to Page 2 of 13, just looking at the first year, 1994, you included such utilities as the Public Service Company of New Hampshire and Baltimore Gas & Electric, and they're not southeastern coastal utilities, are they?

A I said in my testimony that I included southeastern coastal utilities plus other utilities along the Atlantic Coast. The other ones you mentioned are very similar in the nature of coal procurement to that of Progress except that the delivery, the delivered distance is, is farther. On average the New England utilities are something like 50 percent further than Jacksonville, for example. But that's the only difference.

Q We'll get to the transportation issue, Mr. Windham.

A Okay.

Q But you would concede that those two utilities and others in your list are not southeastern coastal utilities; correct?

MR. YOUNG: Objection, asked and answered.

THE WITNESS: They are not southeastern. They're in New England.

BY MR. WALLS:

Q Thank you. And you mentioned transportation costs. And you would agree that the delivered prices reported on FERC Form 423 that you use in your comparison of PEF coal purchases to other utility foreign purchases include transportation costs; right?

MR. YOUNG: Objection, argumentative, calls for a legal conclusion.

THE WITNESS: Yes, I do.

BY MR. WALLS:

Q You did not, however, calculate by year the term -- I'm sorry.

CHAIRMAN EDGAR: Mr. Windham, you need to allow me to rule on the objection.

THE WITNESS: I'm sorry.

CHAIRMAN EDGAR: Okay?

Mr. Walls, let's try it in a slightly different phrasing.

BY MR. WALLS:

Q Okay. Mr. Windham, do the FERC Form 423s include transportation costs?

A Yes, they do.

Q And in your calculation, your analysis in BW-3 and BW-4 for foreign coal comparisons to PEF and Colorado coal comparisons, you did not calculate by year the transportation piece of those delivered prices for the utilities; correct?

A Not for all utilities. I put some data -- I had some information like that and I put some data -- we have in our FPSC 423 forms the, the, a breakout of the commodity and transportation costs for Florida utilities. And so I know what the -- I know what the, the transportation versus the, versus the commodity cost is for the Florida utilities, and I also know a good bit about some of the other utilities and some of them are very comparable. Their, their short-haul legs are very comparable to the numbers in my BW-7 which is for Florida utilities.

Q Mr. Windham, at Page 123 of your deposition, Lines 17 to 24, I asked you the following question, you gave the following answer:

"So it's fair to say that for each of those numbers that are listed in BW-3 that was paid by these utilities for South American coal you did not go back and say I'm going to separately calculate what the transportation piece of this coal was and determine what part of that price they paid was transportation; correct?"

Answer, "No, I didn't do that."

That's a correct statement; right?

A That is correct. But I also put in my testimony the short-haul cost for Florida utilities from some of the FPSC 423 forms, and I, and I also provided information about comparisons between some of the other utilities that weren't Florida with Florida.

Q Mr. Windham, you would agree with me that in your analysis in Exhibit BW-3, based on the comparison of the foreign market to PEF prices, that you were comparing compliance coal because PEF can only burn compliance coal at CR5; right?

A That's actually not true, but, okay.

PEF, PEF, PEF has to, has to meet environmental regulations. And what happens is that utilities often purchase some coal that has more than, more than compliance level, more than compliance level sulfur, for example, and some that has less. And they blend it to -- and as long, as long as the blend meets the compliance level, then there's no problem.

Q Mr. Windham, if you could refer to on the screen Page 133 of your deposition, Lines 11 through 16, where I asked the following question, you gave the following answer:

Question, "By the way, before we get there, you did this calculation in Exhibit BW-3 based on compliance coal from a foreign market compared to compliance coal that Progress purchased because Progress can only burn compliance coal at CR4 and 5; correct?"

Answer, "That's right."

That's an accurate statement; right?

A That statement is not complete. And in other places I noted that you can, in fact, blend coal, and that as long as, as long as the blend meets, meets the compliance level, it's okay.

Q Mr. Windham, do you recall in your deposition that we went through your Exhibit BW-9, which was your composition of FERC data that you used for BW-3?

A Yes, I remember that.

Q And, in fact, we went through and looked at several of the utilities that you had included in your analysis, and, in fact, one was on Page 23 of your BW-9 involving Gulf Power foreign purchases for 1996 where you agreed that most of the purchases were not compliance coal; right?

A I agree that I was aware that some of the coal on, on, on that, on that sheet was not compliance, but that was true for both Progress and also for, for the other utilities.

And as a matter of fact, before I, before I, before I filed my testimony I did a comparison for Progress versus the other utilities, and what I found was that for every year the average of the sulfur level in the other utilities was less than that for Progress. So since, so since in general the foreign coal had less sulfur than, less, a lower level of the sulfur than Progress -- now I'll note that I even include that on some of my BW-9 pages and also on some of the BW-3 pages. And so since I, since I noted that that was the case, that both Progress coal and also the foreign coal that I was comparing had some noncompliance coal and on average the Progress was higher, it did not -- and also the fact that most of the coal was compliance, it did not appear to be a major factor or significant to take out for both Progress and the other utilities the noncompliant part.

Q Mr. Windham, in your deposition didn't you tell me that you didn't attempt in each of the years to go through BW-9 and identify the coal that was not compliance coal and remove it from your BW-3?

A I did not -- I did a macro level filter where I calculated the average, average sulfur level for both, for both -- for any given year for both the foreign coal and the Progress coal, and what I found was that on average the Progress coal had a higher level than the, than the foreign coal. And I -- and thus I did not go through on a record by record -- to do it record by record I would have had to make a conversion using a formula and the, and the -- for each record the Btu value of the coal and so forth, I would have to do that for each record, and I didn't do that.

Q And, Mr. Windham, it's fair to say that you also did not try to determine, for example, in 1996 who PEF should have bought foreign coal from.

A No, I did not.

Q And you also, using the same year 1996 as an example, did not try to calculate whether the ratepayer would have been better off and by how much if PEF had done something different in 1996; correct?

A No. I only looked at which, which coal on average was the most cost-effective.

Q And if we went through each of the years in your analysis, you did not determine how much coal, from whom and what the delta would have been had PEF done something different from what they did and purchased more foreign coals; correct?

A I'm sorry. Repeat the question.

Q Sure. If we went through each of the years in your analysis, you did not determine how much coal, from whom and what the delta would have been had PEF done something different from what it did and purchased more foreign coals; correct?

A In my testimony I did determine how much foreign coal I thought that Progress could have purchased without causing problems with contract, with other contracts or with a spot and that kind of thing. So I determined how much I thought Progress could purchase, but I did not specifically look at who -- which, which mine, for example, they might have purchased it from.

Q Mr. Windham, I'm going to show you your deposition at Page 86, Lines 23 to 25, carrying over to Page 87, Lines 1 to 8, where I asked you the following question, you gave the following answer:

"I'm just curious as to -- that's all I'm getting at. I'm just curious as to what you've done as you sit here today, and, again, I can go through each year if you want, you know, I could go to 1997 and say how much coal, from whom and what would have been the delta? But if you can tell me you haven't done that analysis, that's all I'm getting at."

Answer, "I've not done that analysis. I put the information in there from which other people could do such analysis given the information, this and other information."

That's what you said in your deposition and that was an accurate statement; right?

A Yes. As I said before, I was, I was putting in, into the record information on what the, the prices of the various coals procured by the various utilities were, and that was the first step. And I was not going to, until I looked at the other part, which was whether or not, the reason why Progress might not have purchased what appeared to be the cheapest coal, until, until that was looked at fully through discovery, I wasn't going to bother and try and make a calculation about what, what the difference would be. But that would be a pretty easy calculation based on the information that I have in my testimony for someone to make.

Q Mr. Windham, you would agree with me that your comparison of the average contract and spot PEF purchases as reported on FERC Form 423s from 1994 to 2005 to the median delivered prices reported for foreign bituminous coal purchases by other utilities was not intended for prudence or anything like that; correct?

MR. YOUNG: Objection, argumentative, calls for a legal conclusion.

THE WITNESS: Well, as I noted --

CHAIRMAN EDGAR: Mr. Windham, hold on.

THE WITNESS: Okay. I'm sorry. I'm sorry.

CHAIRMAN EDGAR: Rephrase.

MR. WALLS: I'm just trying to get at what his opinion is and what it is not, and that's --

BY MR. WALLS:

Q Mr. Windham, you would agree that the average price comparison that you did with respect to foreign bituminous coal purchases was not intended for prudence or anything like that; right? That's what you intended?

A I did not intend that I would use it for that purpose.

Q And, in fact, you called it a ballpark type comparison; correct?

A Yes.

MR. WALLS: Thank you. No further questions.

CHAIRMAN EDGAR: Mr. Burgess.

CROSS EXAMINATION

BY MR. BURGESS:

Q Just with regard to the second to the last question, you were in the middle of an answer when the last question was, was asked. You, you had said that you were saying that you did not create it for the purpose of yourself calculating coming up with a prudence evaluation, and then you said "but" and the next question came to you. Did you have anything further to say?

MR. WALLS: I'm going to object. That's not cross-examination.

CHAIRMAN EDGAR: Mr. Burgess, do you have a question for the witness?

MR. BURGESS: Yes. Did you -- do you have -- well, first of all, I think that's perfectly legitimate cross-examination. There's nothing -- I mean, he's cited no rule for which the objection stands. But the cross-examination goes to -- the question I asked goes to and flows from his direct testimony precisely as the question asked by Mr. Walls. I'm, I'm asking the same question Mr. Walls asked.

CHAIRMAN EDGAR: Then ask the question, please.

BY MR. BURGESS:

Q Okay. Did you, did you -- when you did your study, did you do it for the purpose of arriving at a prudence conclusion?

A My testimony was for the purpose of putting information in the record from which others could look at the other issue, which was why Progress didn't appear to be procuring the most cost-effective coal. And I believe that my, my chosen summary, summary measure for the foreign coal, which is the median of the average delivered prices, I think that is a reasonable comparison that Progress might have been expected to be able to meet since the majority of utilities that are below that in general are, are ones that have an additional transportation cost leg that's more than average or it might be in New England and further, further away than average. So I think that my median of average delivered prices is a conservative summary measure to compare the Progress prices to, though I did not intend that my, that my testimony go into the prudence issue because I was leaving that for others to do.

MR. BURGESS: Thank you, Mr. Windham. That's all I have, Madam Chair.

CHAIRMAN EDGAR: Thank you.

Mr. McWhirter.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Mr. Windham, to the casual observer of your testimony it becomes a little bit difficult to draw the comparisons, at least for me, and I was wondering if you would look at your BW-3, which is also identified as staff Exhibit 157 for identification.

A Okay. Which page?

Q Let's see. I was looking at Page 1 of 13 first.

A Okay.

Q And when you're using the PEF price for U.S. for compliance Appalachian coal, the number used is -- I'm looking at '94 now just for illustrative purposes, the number you're using is 177.13. And that number is not dollars per ton but rather, as I understand your testimony, it's cents per million Btus; is that correct?

A That's correct.

Q And the reason you do that is so that you can come up with a comparable number when comparing coal purchases with different Btu values and so forth? I mean, different, yeah, Btu values and tons and so forth; is that right?

A Yes. It takes into account the differences in Btu values and allows you to compare them on a comparable delivered price basis.

Q In mathematics I guess you'd say you're bringing it to the lowest common denominator.

A To a comparable level.

Q And that's an appropriate methodology that's generally used by people who are in this practice and trade as far as you know?

A Yes. That's the standard, standard method that most utilities look at to determine what's the most cost-effective option.

MR. BURNETT: Madam Chairman, if I could object to this friendly cross-examination. I believe this is directly against your admonishment in the beginning that this shouldn't be an opportunity for five direct examinations to take place. The purpose of cross-examination is simply impeachment, and this is simply trying to rehabilitate Mr. Windham, a chance that we don't have as the utility and the defendant in this case.

MR. McWHIRTER: Ms. Chairman, I am certainly not trying to impeach the voracity of Mr. Windham. I think he's a highly credible witness. But for common understanding, I was not trying to recreate direct testimony, I was trying to -- it's hard for people to understand fairly complex things, and I was trying to get it into a frame of reference that I could understand. And it has to do with the questions that were asked on cross-examination that seemed to indicate that he was comparing apples and oranges and things like that, so --

CHAIRMAN EDGAR: We had kumquats and everything in there at one point in time.

I was curious as to who in this room qualifies as a casual observer. But moving on, I did at the beginning of this proceeding ask that all parties work cooperatively and limit friendly cross, and I will ask that again. And I will ask it as we proceed into the rebuttal portion of this proceeding as well. I realize that it's about lunch time on the third day, we have a number of witnesses to go through. So, Mr. McWhirter, I'm going to give a little latitude and allow you to continue with a few questions, but would ask you to keep my comments in mind.

MR. McWHIRTER: You're very gracious. I tried to -- I think I can work it down to one last question, but while I was listening to you I forgot what it was.

BY MR. McWHIRTER:

Q Oh, yeah. The essence of the Public Counsel's case deals with the differential between Powder River Basin coal and the price that Progress Energy paid. You take a different tack and you're looking only at foreign coal and the comparison of what Progress Fuels paid for foreign coal compared to other equivalent utilities; is that correct?

A Yes. I only very recently became aware of the fact that the, the unit, the Crystal River unit, Crystal River 4 and 5 units were, were constructed with, with, to be able to burn the Powder River Basin coal. And all of my discovery that I did through 2000, from 2000 to 2005 and 2006 related to bituminous coal that might have been done. And as a part of that process I did request first one audit and then another audit of the next year. And we went through a process of looking at these various things through a series of audits and, and a spinout docket and then further discovery on the coal prudence issue, procurement --

Q If I may --

A -- in 2005 and 2006.

Q If I may be permitted one final question. The prices you use are the delivered price, so it includes not only the cost of the coal that was purchased that was equivalent type coal but also the cost of transportation. Can you give me an evaluation of the relative portion of the costs in these analyses that related to transportation and other handling as opposed to the price of coal itself?

A You can actually find some of that in my BW-7 if you know how to make calculations between dollars per ton and, and cents per million Btus and that kind of thing. But, in general, the commodity price is the largest price. And if we're talking foreign coal, the transportation costs -- because the foreign coal is delivered in large ocean vessels that might have as much as 60,000 tons, for example, and delivered to a terminal, the delivery price of such a coal in an ocean vessel like that is relatively low compared to the commodity price.

So, for example, on a number during some, some years that I would be aware, I will be on the order of $4 a ton would be a delivered price to, from Colombia to an ocean terminal in Florida, and the commodity price was much bigger, much bigger than that.

Likewise, I mentioned that there were some additional short leg costs. Some coals -- some utilities brought it into a terminal and then had to transload and deliver by barge or truck or something to their plant. So those, those additional costs were there also. And they varied with, with the utilities depending on what kind of additional short-haul costs they had.

But an example, for example, if you look at Gulf Power, my BW-7 actually has some of the short-haul costs in there for Gulf Power. And it might be on the order of, let's just say for, for Crist, 10 to 12 cents per million Btus might be the short-haul cost that you would find in my BW-7 if you convert the dollars per ton to cents per million Btus. And like for some other, other utilities like Daniel, it had a bigger short-haul cost, for example.

MR. McWHIRTER: I'll quit, Ms. Chairman.

CHAIRMAN EDGAR: Questions from others? No? Mr. Brew says no. Ms. Bradley says no. Mr. Twomey is absent, which I'm going to make the conclusion that that means no as well.

And so Commissioners. Commissioner Carter.

COMMISSIONER CARTER: Thank you.

Mr. Windham, in the discussion you said that the information that you provided was not to determine prudence, that would be left for others. Remember that line of questioning?

THE WITNESS: That's correct.

COMMISSIONER CARTER: In this case as presented in the information has anyone made such an evaluation, and, if so, can you point me to where it is?

THE WITNESS: I'm sorry. You mean some other party?

COMMISSIONER CARTER: You said in the discussion about prudence of costs and the coal and all, you said you have not made that determination, you left that for others to do. So I'm saying have any others, in whatever they may be situated, have any other parties in this case made such a determination, and, if so, where is it so I can look at it?

THE WITNESS: What I was saying in my testimony in deposition with regard to the fact that I was not trying to determine prudence before, before, before all the case was in -- in other words, I was putting information into the record on the comparable cost of the various coals to different utilities, that kind of thing, and I was, I was going to leave the decision to other parties to make, make a recommendation to you and for the Commissioners to decide about the prudence issue based on putting together the data that I put in the record regarding the relative cost of the various options, putting that together with the reasons why Progress might not have purchased what appeared to be the most cost-effective coal. That was to be left to discovery and for someone to make a recommendation at a later time. I don't think that phase has happened yet.

COMMISSIONER CARTER: Thank you, Madam Chair.

CHAIRMAN EDGAR: Thank you.

Mr. Young, redirect.

MR. YOUNG: Thank you, Madam Chair. Briefly.

REDIRECT EXAMINATION

BY MR. YOUNG:

Q Mr. Windham, if you can turn to Page BW-3 of your prefiled direct testimony exhibit.

A Yes.

Q As you look through BW-3, did you calculate the average of each utility, the average delivered price of each utility?

A Yes. I calculated the average delivered price for each utility, and I actually calculated it for, in total and also for spot and contract.

Q Now looking at in, in 1994, BW-3, Page 2 of 13, in 1994 did Progress Energy Florida purchase foreign bituminous coal based on a contract basis?

A No.

Q So that's, that's the reason you only have a spot purchase for them; correct?

A That's correct.

Q Okay. You also mentioned focusing on, on BW-3, Page 2 of 13. You have Public Service Company of New Hampshire in here; correct?

A Yes, I do.

Q And what, under D Price what is that average delivered price?

A For, for contract it's 142.10 and for spot it was 163.83. You said New Hampshire, didn't you?

Q Yes, sir.

A Okay. Fine.

Q And it's your testimony that Public Service New Hampshire has a 50 percent greater transportation cost than Progress Energy Florida?

A Not necessarily. They have a 50 percent greater distance from, from Jacksonville.

Q To?

A To that, to that particular facility. And it's more like 35 percent further than to Mobile, for example.

Q And their average delivered price is lower than Progress Energy Florida; correct?

A For contract.

Q For contract; correct?

A Yes.

Q And that -- Progress Energy Florida's price is 177.13 for 1994?

A I'm sorry?

Q And that average delivered price for Progress Energy Florida CAPP for 1994 is 177.13?

A Yes, for contract.

Q Okay. Now you were asked about the, and not to be exhaustive about it, you were asked about comparing average versus median. I think you said that you compared, you took the average of each company; correct?

A I took -- yes. If you look at any page here, I, I took an average -- I calculated, in BW-9 I calculated the average delivered price for all of the utilities for each year, and so I have an average delivered price for each utility, for each of the foreign utilities, I mean, each of the utilities that use foreign coal and I also have an average delivered price for Progress.

Q So if one wants to do an average-to-average comparison not using your methodology, they can?

A Well, if you're going to compare a group of data like this group of data we're looking at on Page 2, if you're going to compare a group, you have to do some kind of summary measure. And since, and since we have a lot of outliers in this set of data and since outliers cause problems with the, with doing a weighted average, in my opinion a more reasonable summary measure -- in fact, I think the most reasonable summary measure for this data would be the median of the average service, average delivered prices of the various utilities, that would be the most reasonable summary measure to use to compare this group of data to the Progress number.

Q And my final questions are, is it your job to determine the amount of coal Progress Energy should have purchased?

A I'm sorry?

Q Is it your job to determine the amount of coal Progress Energy should, Progress Energy Florida should have purchased for any given year?

A Do you mean how much from the various sources?

Q Yes. Is it your job to determine that?

A No.

MR. YOUNG: Okay. No further questions, Madam Chairman.

CHAIRMAN EDGAR: Okay. Let's take up the exhibits. I have 156 to 165.

MR. YOUNG: Madam Chairman, at this time we'd ask that Mr. Windham's Exhibits 166 to 165 be moved -- 156 to 165 be moved into the record.

CHAIRMAN EDGAR: Exhibits 156 through 165 will be moved into the record as evidence.

(Exhibits 156 through 165 marked for identification and admitted into the record.)

MR. BURNETT: Madam Chairman?

CHAIRMAN EDGAR: Mr. Burnett.

MR. BURNETT: Please forgive my interruption. We're not trying to reargue the motion to strike, but I think just to make the record clear we would note our objection to Mr. Windham's testimony and exhibits. I'm, again, not asking for the prehearing officer to rule again, but just to make the record clear.

CHAIRMAN EDGAR: The previously registered, previously registered objection is noted for the record. Thank you.

MR. YOUNG: Thank you, Madam Chair.

CHAIRMAN EDGAR: Thank you.

Mr. Windham, thank you. You're excused.

MR. YOUNG: May this witness be dismissed?

THE WITNESS: I'm sorry?

CHAIRMAN EDGAR: The witness may be dismissed.

MR. YOUNG: Thank you.

CHAIRMAN EDGAR: Thank you.

Okay. I have 12:30, 12:35. I think it's a good place to break for lunch. Let's come back at 1:45. Does that work? Okay. Hearing no objection, we are on lunch break until 1:45, and we will begin with Witness Stewart.

(Lunch recess.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 13th day of April, 2007.

Linda Boles

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