BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 040206-EI

In the Matter of:

PETITION TO DETERMINE NEED FOR TURKEY POINT UNIT 5 ELECTRICAL POWER PLANT, BY FLORIDA POWER & LIGHT COMPANY.

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VOLUME 1

Pages 1 through 157

PROCEEDINGS: HEARING

BEFORE: CHAIRMAN BRAULIO L. BAEZ
COMMISSIONER J. TERRY DEASON
COMMISSIONER LILA A. JABER
COMMISSIONER RUDOLPH "RUDY" BRADLEY
COMMISSIONER CHARLES M. DAVIDSON

DATE: Wednesday, June 2, 2004

TIME: Commenced at 9:35 a.m.
Concluded at 1:45 p.m.

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

REPORTED BY: TRICIA DeMARTE, RPR
Official FPSC Reporter
(850) 413-6736

APPEARANCES:

R. WADE LITCHFIELD, ESQUIRE, and NATALIE F. SMITH, ESQUIRE, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, and SUSAN F. CLARK, ESQUIRE, Radey Thomas Yon & Clark, P.A., 313 North Monroe Street, Suite 200, Tallahassee, Florida 32301, and KENNETH HOFFMAN, ESQUIRE, Rutledge Law Firm, P. O. Box 551, Tallahassee, Florida 32302, and CHARLES A. GUYTON, ESQUIRE, Steel Law Firm, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301, appearing on behalf of Florida Power & Light Company.

STEPHEN C. BURGESS, ESQUIRE, Deputy Public Counsel, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399, appearing on behalf of the Citizens of the State of Florida.

JENNIFER BRUBAKER, ESQUIRE, FPSC General Counsel's **Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida** 32399-0850, appearing on behalf of the Commission Staff.

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
1	Comprehensive Proposed Stipulated Exhibit List	9	10
2	Staff Composite Exhibit	10	12
3	Need Study For Electrical Power Plant 2007	10	12
4	(Confidential) Need Study Appendix C-5	10	12
5	Need Study Appendix C	10	12
6	WEA-1	10	12
7	Need Study Appendix G	10	12
8	MPD-1	10	12
9	Need Study Appendix E	10	12
10	LEG-1	10	12
11	LEG-2	10	12
12	LEG-3	10	12
13	LEG-4	10	12
14	LEG-5	10	12
15	LEG-6	10	12
16	LEG-7	10	12
17	LEG-8	10	12
18	LEG-9	10	12
19	LEG-10	10	12
20	LEG-11	10	12
21	LEG-12	10	12

EXHIBITS (Continued)

NUMBER:		ID.	ADMTD.
22	LEG-13	10	12
23	Need Study Appendix J	10	12
24	DNH-1	10	12
25	DNH-2	10	12
26	DNH-3	10	12
27	DNH-4	10	12
28	DNH-5	10	12
29	DNH-6	10	12
30	DNH-7	10	12
31	DNH-8	10	12
32	Need Study Appendix A	10	12
33	Need Study Appendix K	10	12
34	Need Study Appendix L	10	12
35	Need Study Appendix N	10	12
36	NDR-1	10	12
37	NDR-2	10	12
38	NDR-3	10	12
39	Need Study Appendix B	10	12
40	Need Study Appendix D	10	12
41	Need Study Appendix H	10	12
42	Need Study Appendix I	10	12
43	Need Study Appendix O	10	12
44	RS-1	10	12

EXHIBITS (Continued)

NUMBER:		ID.	ADMTD.
45	RS-2	10	12
46	RS-3	10	12
47	RS-4	10	12
48	RS-5	10	12
49	Need Study Appendix M	10	12
50	Need Study Appendix P	10	12
51	Need Study Appendix C-1	10	12
52	Need Study Appendix C-2	10	12
53	Need Study Appendix C-3	10	12
54	Need Study Appendix C-4	10	12
55	SRS-1	10	12
56	SRS-2	10	12
57	SRS-3	10	12
58	SRS-4	10	12
59	SRS-5	10	12
60	SRS-6	10	12
61	SRS-7	10	12
62	SRS-8	10	12
63	SRS-9	10	12
64	SRS-10	10	12
65	SRS-11	10	12
66	SRS-12	10	12
67	SRS-13	10	12

EXHIBITS (Continued)

NUMBER:		ID.	ADMTD.
68	SRS-14	10	12
69	AST-1	10	12
70	AST-2	10	12
71	Need Study Appendix F	10	12

P R O C E E D I N G S

CHAIRMAN BAEZ: We'll call the hearing to order. Counsel, read the notice, please.

MS. BRUBAKER: Yes, Chairman. Pursuant to notice published April 30th, 2004, this time and place has been set for a hearing in Docket Number 040206-EI. The purpose of the hearing is set forth more fully in the notice.

CHAIRMAN BAEZ: Thank you. And we will take appearances.

MR. LITCHFIELD: Good morning, Mr. Chairman. My name is Wade Litchfield appearing on behalf of Florida Power & Light Company. Also here with me today is Mr. Charlie Guyton of the Steel, Hector, Davis Law Firm; Ken Hoffman of the Rutledge, Ecenia, Purnell & Hoffman Firm; and Susan Clark, Radey, Thomas Yon & Clark; and my colleague from Florida Power & Light Company, Natalie Smith also.

CHAIRMAN BAEZ: Thank you. Mr. Burgess.

MR. BURGESS: Mr. Chairman, I'm Steve Burgess; I'm here for the Office of Public Counsel.

MS. BRUBAKER: And Jennifer Brubaker on behalf of the Commission.

CHAIRMAN BAEZ: Thank you. And we've got preliminary matters?

MS. BRUBAKER: Yes, sir, there's a number of preliminary matters. The first of which I would recommend is the marking of the exhibits. Staff and the parties throughout the prehearing process have agreed to stipulate to a number of exhibits. They are on a list which, I believe, has been provided to all the parties, Commissioners, and the court reporter. It's marked Exhibit Number -- I would recommend that it be Exhibit 1. The description is comprehensive proposed stipulated exhibit list.

In an effort to facilitate the entry of these exhibits what staff has done is listed every exhibit that has been proposed as stipulated. And in lieu of reading and marking each exhibit for the record, I simply recommend that the list itself be marked as Exhibit Number 1 and all the other exhibits be marked thereafter in sequential order as indicated on the list.

CHAIRMAN BAEZ: Very well. Mr. Litchfield, have you had a chance to look over the list and make sure that there's no corrections that need to be made?

MR. LITCHFIELD: We have looked over the list, and it is complete.

CHAIRMAN BAEZ: Okay. Ms. Brubaker, first of all, let's go ahead and mark the comprehensive list as Exhibit 1.

(Exhibit 1 marked for identification.)

CHAIRMAN BAEZ: And I'm showing --

MS. BRUBAKER: I would move that that exhibit be admitted into the record.

CHAIRMAN BAEZ: Without objection, show Exhibit 1 admitted into the record.

(Exhibit 1 admitted into the record.)

CHAIRMAN BAEZ: And I am showing the list contains Exhibits 2 through -- that would be numbered 2 through 71; is that correct?

MS. BRUBAKER: That's correct. And just for the sake of clarification, Exhibits 1 and 2 would be proffered by staff, 3 through 71 are proffered by FPL.

CHAIRMAN BAEZ: Let the record show the exhibits that have been proposed marked according to the list contained in Exhibit 1; that would be Exhibits 2 through 71 and their corresponding sponsors.

(Exhibits 2 through 71 marked for identification.)

MS. BRUBAKER: An additional preliminary matter, Chairman, would be that staff has provided the panel, the parties, and also the court reporter a list of all testimony in this docket. And again, in the prehearing process, the parties and staff have agreed that they can stipulate to the entry of this testimony. And I would recommend it would be appropriate at this time for FPL to request that the testimony be inserted into the record as read.

CHAIRMAN BAEZ: Mr. Litchfield, you want to take that up?

MR. LITCHFIELD: Yes, I will do so, Mr. Chairman.

FPL would move that the testimony filed March 8th of 2004 of the following individuals be moved into the record today as though read: Rene Silva, Steven R. Sim, Moray P. Dewhurst, William E. Avera, C. Martin Mennes, N. Dag Reppen, Leonardo E. Green, Gerard J. Yupp, David N. Hicks, and Alan S. Taylor.

CHAIRMAN BAEZ: Very well. Without objection, show the testimony of witnesses Silva, Sim, Dewhurst, Avera, Mennes, Reppen, Green, Yupp, Hicks, and Taylor, and I will note for the record that the testimony of Witness Reppen also contains an errata sheet that was subsequently filed I'm showing here, show that testimony inserted into the record as though read.

MS. BRUBAKER: And Mr. Chairman, I'll also point out just for clarification, with regard to the exhibit list, there are some notations there at the end of that list that some very minor modifications were made by that same May 27th, 2004 errata filing, and those exhibits should be regarded as having incorporated those small changes.

CHAIRMAN BAEZ: Very well. Let the record show --

MS. BRUBAKER: And it is possible I've just missed this, sir, you identified the exhibits. Were they actually moved into the record?

CHAIRMAN BAEZ: Not yet, but we're going to that do that right after all the testimony that sponsors them is moved in. And I guess now is the time; correct?

So without objection, show Exhibits 2 through

71 admitted into the record. If we didn't do it before, we did it now.

(Exhibits 2 through 71 admitted into the record.)

MS. BRUBAKER: Thank you.

CHAIRMAN BAEZ: Great. What else do we have, Ms. Brubaker?

MS. BRUBAKER: I'm aware of no other preliminary matters at this time. I understand that a continuance may be appropriate until 1:30.

CHAIRMAN BAEZ: We're going to continue the hearing until 1:30 or recess until 1:30. At that point I think we've got some proposed stipulations that will need to be either taken up or addressed in the context of perhaps a recommendation from staff on the issues.

MS. BRUBAKER: That's correct.

CHAIRMAN BAEZ: Is there a preferable way of going through it? Is there anything that we need to know walking out right now?

MS. BRUBAKER: I'm not aware of anything. We can either take them issue by issue and address any questions the Commissioners may have regarding those proposed stipulations, or we can offer background about the case in general if that's also desired.

CHAIRMAN BAEZ: Okay. And we'll do that at the appropriate time when we reconvene at 1:30.

Commissioners, you know, you have the stipulations with you, and if you have questions, 1:30 when we reconvene will be the appropriate time to take them up. If there's nothing else at this point, we're in recess until 1:30 Thank you.

(Recess.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF RENE SILVA

DOCKET NO. 04____-EI

March 8, 2004

Q. Please state your name and business address.

A. My name is Rene Silva, and my business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. By whom are you employed and what position do you hold?

A. I am employed by Florida Power & Light Company (FPL) as Director, Resource Assessment and Planning (RAP).

Q. Please describe your duties and responsibilities in that position.

A. I manage the RAP, the department that is responsible for developing FPL's integrated resource plan (IRP) and other related activities, such as analyzing demand side management (DSM) programs, developing system production cost projections, developing FPL's demand and energy forecasts, and administering wholesale power purchase agreements (PPAs).

Q. Please describe your education and professional experience.

A. I graduated from the University of Michigan with a Bachelor of Science Degree in Engineering Science in 1974. From 1974 until 1978, I was employed by the Nuclear Energy Division of the General Electric Company in the area of nuclear fuel design. While employed by General Electric, I earned a Masters Degree in Mechanical Engineering from San Jose State University in 1978.

I joined the Fuel Resources Department of FPL in 1978, as a fuel engineer, responsible for purchasing nuclear fuel. While employed by FPL, I earned a Masters Degree in Business Administration from the University of Miami in 1986. In 1987 I became Manager of Fossil Fuel, responsible for FPL's purchases of fuel oil, natural gas and coal. In 1990 I assumed the position of Director, Fuel Resources Department, and in 1991 became Manager of Fuel Services, responsible for coordinating the development and implementation of FPL's fossil fuel procurement strategy. In 1998 I was named Manager of Business Services in the Power Generation Division (PGD). In that capacity I managed the group that is responsible for coordinating (a) the development of PGD's strategic plan for the effective and efficient construction, operation and maintenance of FPL's fossil generating plants, (b) the preparation of PGD annual budgets and tracking of expenditures, and (c) the preparation of reports related to fossil generating plant performance. On May 1, 2002, I was appointed to my current position.

Q. What is the purpose of your testimony?

A. My testimony addresses seven areas. First, I summarize the determination of need FPL is seeking in this proceeding. Second, I introduce FPL's witnesses and FPL's Need Study and Appendices. Third, I summarize FPL's 2007 capacity need. Fourth, I summarize FPL's assessment of self-build alternatives to meet FPL's 2007 capacity need and FPL's selection of Turkey Point Unit 5 as its Next Planned Generating Unit (NPGU). Fifth, I address in detail FPL's Request for Proposals (RFP) issued to identify additional potential alternatives to meet FPL's 2007 need and describe FPL's RFP process. Sixth, I summarize FPL's analyses of proposals submitted in response to FPL's RFP, and the comparison of these proposals to FPL's NPGU, culminating in the selection of Turkey Point Unit 5 as the best, most cost-effective alternative to meet FPL's 2007 need. Finally, I address the significant adverse consequences FPL and its customers face if the Turkey Point Unit 5 determination of need is not granted.

Q. Are you sponsoring an exhibit in this case?

A. Yes. I am sponsoring an exhibit consisting of 5 documents attached to my direct testimony. Those 5 documents are:

- Document RS-1, a list of the four organizations that responded to FPL's RFP, and the number and type of proposals submitted by each,
- Document RS-2, a list of proposals received by FPL in response to its RFP, and the capacity, technology and term of each proposal,

- Document RS-3, Rankings of Portfolios Prior to Announcement of Finalist, including all costs,
- Document RS-4, Summary of Unsatisfied Minimum Requirements for each of the proposed projects, and
- Document RS-5, Final Rankings After Best and Final Offer, including all costs.

Q. Are you sponsoring any sections in the Need Study document?

A. Yes. I am sponsoring the following sections: I, II and IX. I also co-sponsor Sections V, VI and VIII. In addition, I sponsor Appendices B, D, H, I and O.

I. FPL's Request for an Affirmative Determination of Need.

Q. Please explain the relief FPL seeks in this proceeding.

A. FPL seeks from the Florida Public Service Commission (Commission) an affirmative determination of need for Turkey Point Unit 5, a combined cycle unit with a summer capacity rating of 1,144 MWs and a proposed commercial operation date of June 1, 2007. The unit's primary fuel will be natural gas, but it will have the capability to use light oil as backup fuel.

FPL's request for an affirmative determination of need is the culmination of more than a year of investigation and extensive analyses designed to identify the best, most cost-effective alternative available to meet FPL's forecasted

2007 need for capacity. That work included not only FPL's assessment of its 2007 capacity need and analysis of self-build options, but also the preparation, administration and evaluation of an RFP soliciting alternatives to the self-build option.

Q. Why is Turkey Point Unit 5 needed?

A. Turkey Point Unit 5 is needed by FPL to maintain system reliability for its customers. Without the addition of Turkey Point Unit 5, FPL will experience in the Summer of 2007 a reserve margin of only 14.7 percent, well below the 20 percent reserve margin the Commission has approved for FPL. Without the addition of Turkey Point Unit 5, FPL's customers will be served by a less reliable system.

Turkey Point Unit 5 is needed to provide adequate electricity at a reasonable cost to FPL's customers. Turkey Point Unit 5 employs a highly efficient, proven technology with which FPL has considerable experience. It will be a highly reliable and low-cost source of electricity for FPL's customers. Given FPL's industry-leading performance with this type technology, FPL's customers will be well served by this resource addition.

Further, Turkey Point Unit 5 is needed to address the growing imbalance between load and generation capacity in Southeast Florida and the associated increasing reliance on transmission import capability to serve the Southeast

Florida area load. Locating new generation in Southeast Florida improves this imbalance and avoids higher costs related to transmission losses and increased uneconomic operation of Southeast Florida gas turbines.

Q. Is Turkey Point Unit 5 the most cost-effective alternative to meet FPL's and its customers' needs for new resources in 2007?

A. Yes. Turkey Point Unit 5 is the best, most cost-effective option available to meet the needs of FPL and its customers. Turkey Point Unit 5 was selected as FPL's NPGU to meet FPL's 2007 need because it was determined to be the best, most cost-effective alternative from among all the self-build options identified and evaluated by FPL. In addition, Turkey Point Unit 5 subsequently was evaluated against seven alternative portfolios constructed from the 5 proposals received in response to FPL's RFP. None of the seven alternative portfolios was cost-competitive with Turkey Point Unit 5. The closest alternative was at least $271 million, Cumulative Present Value of Revenue Requirements (CPVRR), more costly to FPL's customers than Turkey Point Unit 5. Furthermore, that portfolio did not offer any non-economic advantages over Turkey Point Unit 5. Therefore, FPL has confirmed that Turkey Point Unit 5 is the best, most cost-effective alternative to meet FPL's and its customers' needs for additional resources in 2007.

Q. Is there cost-effective DSM available to avoid or mitigate the need for Turkey Point Unit 5?

A. No. FPL and the Commission already have identified the reasonably achievable, cost-effective DSM available to FPL through 2007, and those DSM amounts were used to develop FPL's 2007 need. Therefore, if there is any additional cost-effective DSM available to FPL, it is not sufficient to avoid or mitigate the need for Turkey Point Unit 5.

II. FPL's Witnesses and Need Study Documents.

Q. How many witnesses is FPL sponsoring?

A. FPL is sponsoring ten witnesses in its direct case. Each witness has prefiled testimony, and most have prefiled exhibits. In addition, most of FPL's witnesses sponsor a portion of FPL's Need Study and Appendices.

Q. Please summarize the topics addressed in the testimony of the other witnesses who will appear on FPL's behalf in this proceeding.

A. Dr. Leonardo Green describes FPL's load forecasting process, discusses the methodologies and assumptions used in that process, and presents the resulting load forecast. Dr. Green's load forecast was used in FPL's IRP analysis to identify FPL's resource need in 2007, and in the economic analysis of the various alternatives identified by FPL and proposed by others to meet that need.

Dr. Steven Sim describes FPL's resource planning process, identifies FPL's additional resource need in 2007, describes FPL's proposed self-build options to meet that resource need, discusses the proposals received in response to the RFP, explains in detail the process FPL followed to perform the economic evaluation of the proposals and FPL's NPGU, and presents the results of the economic evaluation. Dr. Sim demonstrates that the addition of Turkey Point Unit 5 in 2007 results in the lowest cost to FPL's customers. Dr. Sim's testimony also discusses FPL's DSM goals and FPL's DSM programs and plan. He demonstrates that there is not sufficient DSM potential to avoid the proposed generating unit.

Alan Taylor describes his role as an independent evaluator of FPL's Turkey Point Unit 5 and of the new capacity proposals received by FPL in response to its RFP, describes the process he followed and the tools he used to conduct his economic evaluation, presents the results of that evaluation, and explains his conclusion that the addition of Turkey Point Unit 5 constitutes the most cost-effective alternative to meet FPL's resource need in 2007.

David Hicks presents the engineering details of FPL's Turkey Point Unit 5 project, which involves the construction of a new state-of-the-art 4x1 combined cycle (CC) unit. Included in his testimony are the cost and performance specifications of this unit, corresponding to the data used in FPL's RFP analysis.

Martin Mennes discusses FPL's electrical system. He discusses the basis for FPL's concerns arising from the growing imbalance between load and generation in the Southeast Florida area. He also describes the transmission-related assessment that was performed for the RFP.

N. Dag Reppen describes the load flow studies and other transmission assessments and calculations performed to determine the transmission integration costs, system transmission losses and southeast Florida uneconomic dispatch costs associated with the addition of Turkey Point Unit 5 and each of the alternative portfolios considered. Mr. Reppen presents the results of that process.

Mr. Moray Dewhurst describes the importance, from the perspective of FPL and its customers, of ensuring that the entities with whom FPL may enter into a capacity and energy contract have, and will maintain, the level of financial viability necessary to ensure that their facilities will be constructed, completed on schedule, and properly operated and maintained. He also explains the importance of implementing the security provisions necessary to mitigate the adverse impact of failure to perform on the part of these entities. Mr. Dewhurst also describes why an economic evaluation of purchased power alternatives relative to a company's self-build option must include consideration and application of an equity adjustment.

Dr. William Avera addresses the impact of power purchase contracts on FPL's financial leverage and describes the method FPL used to account for this impact in its evaluation of proposals submitted in response to FPL's RFP. His testimony discusses the financial impact associated with purchased power contracts and the importance of recognizing the known costs of these risks in an economic evaluation of power supply alternatives. Dr. Avera concludes that FPL's calculation of the costs associated with the debt equivalent of portfolios including proposals submitted in response to the RFP was based on reasonable assumptions, and that the application of the resulting equity adjustment in FPL's analysis of proposals is consistent both with the Standard & Poor's Corporation (S&P) methodology to calculate the off-balance sheet obligation and prior Florida Public Service Commission (Commission) practice.

Gerard Yupp describes the transportation plan to deliver natural gas and light oil to Turkey Point Unit 5 and testifies to the ready availability of natural gas for Turkey Point Unit 5. Mr. Yupp also supports the fuel price forecast used in FPL's economic analysis of Turkey Point Unit 5 and the alternative portfolios.

Q. What is FPL's Need Study and supporting appendices?

A. The Need Study is a comprehensive overview of FPL's planning process and the RFP process used to identify the Turkey Point Unit 5 project as the best, most cost-effective alternative to meet FPL's 2007 need. The document consists of nine sections:

Section I	Executive Summary
Section II	Introduction
Section III	Description of the Proposed Power Plant
Section IV	FPL's Need for the Proposed Power Plant
Section V	Factors Affecting Selection of the Best Alternative
Section VI	Major Available Generating Alternatives Evaluated
Section VII	Non-Generating Alternatives
Section VIII	Adverse Consequences if the Proposed Capacity Addition Is Delayed or Denied
Section IX	Conclusion

Various portions of the Need Study document and appendices are sponsored or co-sponsored by FPL's witnesses, as explained in their testimony.

III. FPL's Need for Additional Capacity in the Summer of 2007.

Q. Please summarize FPL's need for additional capacity in the summer of 2007.

A. Each year FPL performs a reliability assessment using two reliability criteria, a 20 percent reserve margin and a 0.1 Loss of Load Probability (LOLP). FPL's reliability assessment completed in 2003 determined that FPL needed to add 1,066 MW of capacity in 2007 in order to meet its 20 percent reserve margin criterion during the summer of 2007. FPL also determined that adding the 1,066 MW of new capacity required to meet the reserve margin criterion also would enhance FPL's ability to meet the 0.1 LOLP criterion. Therefore, FPL's capacity need in 2007 is 1,066 MW. Dr. Sim discusses the reliability assessment in detail in his testimony.

Q. Did FPL's reliability assessment that led to its determination of a need to add 1,066 MW by the summer of 2007 include consideration of demand side management on FPL's system?

A. Yes. FPL's reliability assessment included FPL's current DSM goals, which are the Commission's most recent determination of the reasonably achievable, cost-effective DSM available to FPL. Dr. Sim addresses this in more detail in his testimony.

IV. FPL's Assessment of Alternatives to Meet Its Forecasted 2007 Needs.

Q. What important factors did FPL consider in its evaluation of alternatives available to meet FPL's forecasted 2007 capacity need?

A. FPL considered a number of important factors, including but not limited to: cost, performance, location, protection of customers and fuel diversity.

Q. Please explain why "cost" was an important consideration in your assessment of alternatives.

A. The statute that governs determinations of need, which would apply to many potential alternatives, requires the Commission to consider whether the option FPL selects is the most cost-effective alternative to meet its needs. In addition, FPL is obligated to provide to its customers electricity at a reasonable cost. Therefore, even if that statute did not exist, FPL would still be subject to a Commission review of prudence in its choice of a generating alternative. So achieving low cost to customers is of paramount importance in the selection of the generation capacity alternative.

Q. Please explain the importance of a generation alternative's "ability to perform" in your assessment of alternatives.

A. If a generation alternative fails to perform as projected, any perceived cost advantage associated with that alternative might not be realized. In addition, failure to meet the target in-service date and/or perform as proposed and evaluated would have a serious adverse effect on reliability. Therefore, perceived low cost alone is not sufficient to select a given alternative. There must also be assurance that the selected generation alternative will be placed in service when needed and will perform as evaluated. In this regard it is important to consider whether an alternative utilizes a known, reliable technology with proven performance, whether a developer/operator has a proven successful record in the construction and operation of the proposed alternative, whether the entity responsible for the construction and operation of the alternative has the financial strength to weather market adversities and still meet its commitments, and whether a proposer can and will provide material assurances that serve to mitigate the adverse effect of delays and non-performance and that preserve for the customer the perceived benefit upon which the selection of that proposer's alternative is based.

Q. Please address the importance of the "location of resources" in your assessment of alternatives.

A. The location of the capacity addition is an important consideration. For some time now FPL has been informing the Commission and potential suppliers of a growing imbalance between load and generation capacity in the southeast area of FPL's system. Addressing this growing imbalance will require either additional generation located in that area, or additional generation located outside this area combined with significant transmission additions.

Therefore, the location of the capacity addition to be placed in service in 2007 will have a significant effect on the magnitude and cost of transmission enhancements that will be required to maintain reliability in the future, as well as other transmission-related costs such as system transmission losses and the effect of dispatching uneconomically the less efficient gas turbines in Southeast Florida to maintain voltage and area protection.

It is evident that any decision regarding the location of new generation capacity – whether within, or outside of southeast Florida in 2007 - has cost consequences to FPL's customers that must be captured in the economic analysis of options.

Mr. Mennes and Mr. Reppen discuss these issues in detail.

Q. Please explain how the "protection of customers" was an important factor in your assessment of alternatives.

A. FPL has a statutory obligation to serve and is extensively regulated as to its costs and performance. The Commission has jurisdiction over FPL to ensure that FPL is meeting its obligations to its customers.

However, the Commission does not have jurisdiction over entities that supply electricity, or for that matter, fuel, equipment, or other services to FPL. Therefore, the Commission cannot directly protect FPL's customers from these entities in the event of delays, poor performance, misconduct or negligence. FPL's customers and the Commission rely on FPL to provide that protection. The only means FPL has to provide that protection are: (1) entering into contracts with selected entities that can reasonably be relied upon to perform as specified in the contract; and (2) requiring that the contracts FPL enters into with those entities include terms that protect the customers' interests.

Having contract protection is essential, and for that reason FPL goes to great lengths to insist on terms that protect its customers. This applies to the purchase of fuel, the acquisition of combustion turbines, and the procurement of engineering procurement and construction (EPC) services, as well as power purchases.

However, having the right contract terms is sometimes not sufficient. If a supplier becomes financially distressed, it may not be able to perform and could use bankruptcy protection to evade some contract provisions designed to protect customers. This presents two challenges to FPL regarding the RFP. The first challenge is to enter into PPAs with entities that, at least at the time the contract is entered into, can demonstrate in a number of ways that they can perform their obligations under the PPA. The second is to insist on contract terms that are designed to protect FPL's customers even in the event of a supplier's unforeseen financial distress. FPL's RFP process reflects its recognition that it must strive to meet these challenges to protect its customers.

Q. The last factor you mentioned as important in your assessment of alternatives was "fuel diversity," please explain its import.

A. Natural gas fired combined cycle units provide the most efficient means of converting fuel into electricity in FPL's system, and contribute significantly to FPL's low electricity cost. Because of the many significant attractive features of this technology, FPL's system has increased its reliance on natural gas as a fuel source in recent years. However, natural gas prices have exhibited volatility during the last two years, and it is expected that the situation will continue for some time. As a result, FPL has been evaluating other economic alternatives that would enable FPL to achieve greater balance in its fuel mix.

However, as FPL considered resource additions in the 2003 IRP process to meet FPL's need in 2007, the alternatives available to improve FPL's system fuel diversity were very limited. In FPL's view, new solid fuel generation facilities could not be counted on to initiate and complete the process of permitting and construction in the time available. Furthermore, there is still significant uncertainty regarding the type of emission management systems that would be required for new solid fuel facilities, and the cost of those systems. FPL's current evaluation of alternative technologies is considering these uncertainties, as well as the possibility of utilizing natural gas transported as liquefied natural gas (LNG) in the future.

Therefore, FPL stated in its RFP a preference for proposals that would improve FPL's fuel diversity. FPL specifically noted that plants utilizing pulverized coal, circulating fluidized bed coal, petroleum coke or natural gas transported as LNG would contribute to FPL's fuel diversity. Any proposals that would deliver energy from an existing plant or one already under development that utilized these fuels and be priced based on these fuels had the potential to improve FPL's fuel diversity.

Q. With these factors in mind, what alternatives did FPL consider to meet its 2007 resource need?

A. FPL considered 25 different self-build alternatives consisting of combined cycle units and/or combustion turbines in simple cycle operation to meet its 2007 need. Dr. Sim discusses in detail the alternatives considered and the analyses performed. Turkey Point Unit 5 emerged as the best self-build alternative to meet the 2007 need and therefore was identified as FPL's NPGU.

Q. Did FPL issue a Request for Proposals to seek alternative proposals to meet the generation capacity need for 2007?

A. Yes. The Florida Administrative Code Rule 25-22.082 (Bid Rule) requires public utilities to issue an RFP prior to filing a petition for determination of need in accordance with Section 403.519, Florida Statutes. The most cost-effective self-build option identified by FPL to meet its 2007 need, Turkey Point Unit 5, requires a positive determination of need. FPL issued an RFP in compliance with the above requirements in order to determine whether other (non-FPL) alternatives could meet FPL's 2007 need more cost-effectively than Turkey Point Unit 5.

V. FPL's RFP and RFP Process.

Q. Please describe FPL's RFP issued on August 25, 2003.

A. FPL's RFP consisted of a comprehensive document setting forth in detail the terms of the solicitation, supplemented by six appendices, A-F, and two attachments. FPL's RFP is Appendix D to FPL's Need Study.

Q. Did FPL's RFP contain a detailed technical description of FPL's NPGU including financial assumptions and parameters associated with the NPGU?

A. Yes. That information is found on pages 31-39 of the RFP for both FPL's NPGU and FPL's alternative generating unit.

Q. Did FPL's RFP contain a copy of FPL's most recent Ten-Year Site Plan?

A. Yes. FPL's 2003 Ten Year Site Plan was Attachment One to the RFP.

Q. Did FPL's RFP contain a schedule of critical dates for solicitation, evaluation, screening of proposals, selection of finalists and subsequent contract negotiations?

A. Yes, that schedule is found on page 14 of the RFP and was supplemented by text.

Q. Did FPL's RFP contain a detailed description of the criteria and methodology to be used to evaluate alternative generating proposals on the basis of price and non-price attributes?

A. Yes. That discussion is found on pages 28 through 30 of the RFP. It is supplemented by Appendix B, which contains a detailed description of the evaluation methodology, Appendix C, which contains a detailed discussion of the Equity Adjustment methodology used in the economic evaluation, and Appendix E, which provides a detailed discussion of the transmission system-related cost analyses employed in the economic evaluation.

Q. Did FPL's RFP set forth the required application fees?

A. Yes. FPL's application fee was set forth in the RFP on page 18 of the RFP. This passage was subsequently superseded by new language contained in Addendum Three to the RFP, submitted to the Commission dated October 6, 2003.

Q. Was FPL's RFP fee cost based?

A. Yes. FPL used its then most recent RFP to develop a cost-based RFP fee.

Q. Did FPL's RFP contain the best available information regarding system specific conditions?

A. Yes. This information is reflected on pages 2 - 6 of FPL's RFP. It includes a discussion of FPL's 2007 capacity need as well as a discussion of FPL's geographic preference and fuel diversity preference.

Q. Did FPL require bidders to publish newspaper notices in counties in which they proposed to build new plants?

A. Yes, that requirement was specified on page 20 of the RFP.

Q. FPL specified a number of "minimum requirements" in its RFP. Please explain the rationale for these minimum requirements.

A. The "minimum requirements" FPL specified in its RFP were mandatory terms that proposers had to meet. Proposers could not state exceptions to these specific terms. FPL's RFP permitted proposers to state exceptions to other terms of the RFP, and most of the terms of the RFP were not stated as "minimum requirements."

These minimum requirements were necessary to allow FPL to:

1. properly administer the RFP and fairly and completely evaluate all alternatives,
2. enable FPL to comply with the Bid Rule,
3. protect FPL's customers from a proposer's inability to complete proposed new generation facilities on schedule or operate the facility as proposed

and evaluated or acquire and maintain all necessary government permits, licenses and approvals,

4. protect FPL's customers from future higher transmission costs that may result from the implementation of a regional transmission organization (RTO) or independent system operator (ISO) in Florida,
5. maintain system reliability in the event of an unexpected interruption in the delivery of natural gas, and
6. ensure that for any contract entered into as a result of this RFP, all contract terms and payments to be made are subject to Commission approval.

In short, the minimum requirements were designed to enable FPL to conduct a process that would result in the selection of the best, most cost-effective generation alternative to meet the 2007 need, and, to the extent that the selected alternative included one or more proposals, to successfully enter into a contract to secure the benefits of that alternative for FPL's customers, and to ensure that the customers, in fact, would receive those benefits.

Q. Please address the process FPL followed in announcing its August 25, 2003 RFP and providing relevant information to potential bidders.

A. On August 14, 2003, FPL provided notification of its RFP, its pre-issuance meeting with potential bidders and its pre-bid meeting with potential bidders by publishing notices in the Wall Street Journal, Miami Herald, New York Times and St. Petersburg Times, and issuing a press release that was published in a variety of trade publications. The notices included the name and address of the RFP contact person, a general description of FPL's NPGU, and a schedule of critical dates. A copy of the notices and advertisements are provided as Appendix H to the Need Study.

On August 21, 2003, FPL held the pre-issuance meeting with potential bidders in Miami as indicated in the notices published on August 14. At that meeting FPL explained its intent to issue an RFP, its forecasted capacity need, its NPGU, its anticipated RFP process, and the minimum requirements to be met by each proposer. Also, FPL shared with potential proposers key characteristics that would make a proposal more beneficial to FPL's customers and responded to questions posed by the meeting participants.

Q. Did FPL change the terms of its RFP in response to concerns raised by potential bidders at the pre-issuance workshop?

A. Yes. In Addendum One, filed with the Commission on September 4, 2003, FPL gave potential proposers a choice, as requested by the attendees at the pre-issuance meeting, to provide in the proposal's pricing provision either a set of specified annual payments, or in the alternative, initial payment values to be escalated for purposes of the evaluation utilizing a uniform set of indices.

Q. When did FPL issue its RFP?

A. FPL issued its RFP and filed it with the Commission on August 25, 2003. Subsequently, FPL issued 3 addenda to its RFP on September 4 and 12, and October 6, respectively, and filed those addenda with the Commission.

Q. Did FPL hold any meetings with potential proposers after it issued the RFP?

A. Yes. FPL held a pre-bid workshop on September 2, 2003. At this workshop FPL summarized the RFP, discussed the process FPL would follow to evaluate proposals, presented each minimum requirement and explained the basis for each, emphasized the significance of the growing imbalance between load and installed capacity in southeast Florida, and responded to many questions posed by the attendees.

Q. Did FPL further change other aspects of the RFP process in response to concerns raised by potential bidders at the pre-bid workshop?

A. Yes. In response to potential proposers' requests, FPL issued Addendum Two on September 12, 2003, in which FPL communicated to all participants the fuel price forecast it would use in the economic evaluation of proposals submitted in response to the RFP. FPL also extended the cutoff date for questions to be submitted by potential proposers, and sought to expand the options available to proposers to meet the dual fuel requirement.

Q. What means did FPL provide for potential proposers to obtain responses to questions regarding the RFP or the RFP process?

A. In addition to the pre-issuance meeting of August 21, 2003, and the pre-bid meeting of September 2, 2003, FPL created a website on which it listed questions posed by potential proposers and posted responses that would be available to all interested parties. This website was opened on August 14, and 201 questions were listed and answered on the website. In addition to these 201 questions, answers to 32 other questions received by FPL nearer the proposal due date were e-mailed directly to all participants to ensure timely receipt by all. All the questions received and responses posted on FPL's website or answered via e-mail to all participants are included in Appendix I to the Need Study.

Q. What other notable features were included in FPL's RFP?

A. First, FPL included in its RFP a draft PPA to which proposers could choose to take exception regarding any terms other than the minimum requirements. Including the draft PPA enabled prospective proposers to better understand what FPL considers important in protecting its customers. The Bid Rule does not require the inclusion of such a sample PPA or the opportunity to state exceptions, but FPL sought to give prospective proposers as much information as possible to help them submit attractive proposals.

Second, in addition to identifying its NPGU as specified by the Bid Rule, FPL offered a separate option consisting of a smaller FPL generating unit located in southeast Florida. This separate option or "alternative generating unit," could be (and was) combined into portfolios with proposals submitted in response to the RFP. This action increased the number of alternative portfolios, giving proposers more potential opportunities to compete against FPL's NPGU.

Third, FPL employed an independent evaluator to perform an economic assessment in parallel with FPL. Although this is not a requirement, FPL chose to employ one in order to increase the transparency and confirm the results of its economic evaluation process.

Q. The Bid Rule allows a potential participant to file objections to the RFP within 10 days of issuance. Were any objections filed?

A. Yes. Although none of the potential proposers filed any objections, PACE, an industry association, filed 14 such objections. Within 5 days of PACE submitting its objections, FPL filed its response.

Q. What was the resolution of PACE's objections?

A. The Commission heard oral argument on the objections on September 30, 2003. After hearing arguments, all of the Commissioners concluded that PACE's objections did not demonstrate FPL's RFP violated the Bid Rule.

Q. Did FPL make other changes to the RFP?

A. Yes. In response to the discussion at the oral argument, FPL implemented a number of further changes to the RFP. First, the evaluation fee provision was modified to reduce the fee required for variations to a proposal. Second, the minimum financial viability requirement was relaxed from "BBB/Baa2" to "BBB-/Baa3." Third, the schedule for posting financial security amounts was deferred, and the form of security required was modified to mitigate the impact on proposers. Fourth, the wording of the regulatory modifications requirement was amended to incorporate language from the Bid Rule. Fifth, any inference that failure to state specific exceptions to the draft PPA constituted contractual acceptance on the part of the proposer was eliminated. And sixth, the dual fuel minimum requirement was restated to apply to proposals the same continuity and operability requirements that FPL imposes on its NPGU. A more detailed description of these modifications, which were published on October 6, 2003, as Addendum Three, is presented in Appendix D to the Need Study.

Q. Did FPL allow a minimum of sixty days between issuance of its RFP and receiving bids?

A. Yes, FPL did so, as required by the Bid Rule.

Q. Did FPL receive bids in response to its RFP?

A. Yes, FPL received 5 proposals from four entities. Unlike FPL's last solicitation, all the proposers were Independent Power Producers (IPPs). The proposers were Calpine Corporation, Progress Energy Ventures, Southern Power Company and Summit Energy Partners. A list of the proposers, the number of proposals submitted by each, and the type of proposed contractual arrangement is presented in my Document RS-1. The magnitude of each proposal, the proposed technology, and the proposed term of service is presented in my Document RS-2.

Q. In FPL's last RFP, it received proposals from sixteen bidders. Were you surprised that FPL received proposals from fewer bidders in this solicitation?

A. No. There are a number of reasons FPL received fewer bids in this RFP than in its last RFP. I will address several.

First, FPL received no proposals from utility companies in response to this RFP, whereas it received three such proposals in its last RFP. This reflects the reality that there is no longer "spare" utility capacity available to be offered for sale to other utilities in Florida.

Second, and probably most significant, since FPL's previous RFP's there has been a significant downturn in the financial health of many IPP companies.

Of the thirteen IPP proposers who submitted proposals in response to FPL's Supplemental RFP in 2002, nine now have bond ratings below "investment grade." This may well have contributed to the lower number of IPP bids received.

Third, for entities proposing new construction, FPL required entities with a bond rating lower than "BBB-" from S&P or Baa3 from Moody's Investors Service to obtain a guarantee from another entity with bond rating of "BBB-/Baa3" or higher, as a minimum requirement. This appropriately would have had the effect of eliminating unacceptably risky potential bidders.

Fourth, this solicitation was aimed at meeting FPL's need for one year – 2007. The prior RFP sought proposals to meet FPL's needs in two years, 2005 and 2006. In the former case, the multiple-year needs covering 1,722 MWs, offered proposers more chances at being selected because there were more possible combinations in which a proposal could participate. In addition, proposers could submit the same proposal with two different starting dates, 2005 and 2006, and it was counted as one proposal for fee purposes (but two for the purpose of counting total proposals submitted). This year, because FPL was soliciting proposals for a smaller need (1,066 MWs) covering only one year, there were likely to be fewer combinations in which a single proposal could be considered. This may have provided less of an incentive for potential proposers than in the previous RFP.

It should be noted that aside from FPL's last RFP and Supplemental RFP, no other IOU solicitation in Florida has ever received more than four proposals from four proposers. Therefore, the fact that FPL received 5 proposals from four entities is consistent with solicitations by other IOU's.

Q. Please describe the screening of the RFP proposals.

A. FPL first evaluated the proposals in terms of their compliance with the minimum requirements. FPL determined that three entities submitting proposals took specific exception to one or more of the minimum requirements, or otherwise failed to comply with one or more minimum requirements. FPL notified each of these proposers of the nature and extent of its non-compliance, encouraged the proposer to make the changes necessary to comply with all minimum requirements and advised it that failure to comply would result in its proposal(s) not being considered further. FPL also notified these proposers that pending a definitive determination of their compliance with all minimum requirements after their responses were received and evaluated by FPL, FPL would include their proposals in the economic evaluation.

Q. Why did FPL include non-complying proposals in the economic evaluation?

A. FPL sought to give all proposers ample opportunity to revise their proposals to make them compliant, but this would require time. At the same time, FPL wanted to avoid delays in the economic evaluation. Therefore, FPL included the non-complying proposals in the economic evaluation, contingent upon these proposals being modified to comply with all minimum requirements.

Q. Please summarize the economic evaluation process.

A. The economic evaluation consisted of four steps. The first step was to identify portfolios that were potential alternatives to FPL's NPGU. FPL utilized the EGEAS model to create potential portfolios and identified seven portfolios to be evaluated as alternatives to Turkey Point Unit 5 to meet the 2007 need. Two consisted of a single proposal each; two others consisted of two proposals each, and three consisted of one or more proposals combined with FPL's alternative generating unit (CT option). Counting FPL's NPGU, eight portfolios were evaluated.

Second, for each portfolio a total generation-related cost was calculated for the FPL system including that portfolio as part of the FPL system. This cost was developed using the EGEAS model with cost inputs from the proposals and the cost data for FPL's NPGU and FPL's alternative generating unit provided in Section V of the RFP document. Dr. Sim addresses this step in detail.

Third, for each portfolio transmission-related costs were calculated for the FPL system including that portfolio as part of the FPL system. These include the cost of transmission integration, the cost of capacity and energy losses, and increased system operating costs. Dr. Sim and Mr. Reppen address this step in detail.

Fourth, a net equity adjustment (equity adjustment less mitigation offered by completion and performance security) was then calculated for each portfolio to reflect the cost of rebalancing FPL' capital structure, as required to offset the debt equivalent of that portfolio. Mr. Avera and Mr. Dewhurst address this step.

Q. What were the results of the economic evaluation?

A. The Turkey Point Unit 5 is the most cost-effective alternative. The results of the economic evaluation indicate that the closest alternative portfolio had costs that were $266 million, CPVRR, greater than those for Turkey Point Unit 5. The cost of the most costly portfolio was $354 million greater than those for Turkey Point Unit 5. These results are summarized in Document RS-3. Dr. Sim discusses these results in greater detail.

Q. What were the results of the economic evaluation performed by an independent evaluator?

A. The independent evaluator's results confirmed that the Turkey Point Unit 5 is the most cost-effective alternative. Specifically, the results of the independent economic evaluation indicate that the closest alternative portfolio had costs that were $302 million, CPVRR, greater than those for Turkey Point Unit 5. The cost of the most costly portfolio was $433 million greater than those for Turkey Point Unit 5. Mr. Taylor discusses these results in detail.

Q. In your economic evaluation of alternatives, you considered more than generation-related costs, why?

A. The objective of FPL's economic evaluation in first identifying its own NPGU, and then evaluating market proposals in comparison to the NPGU is to select the overall most cost-effective alternative for FPL's customers. This requires that every cost component that can be identified and quantified be reflected in the evaluation. All the costs considered in the economic evaluation, including all transmission-related costs, are real costs that will accrue to FPL's customers as a result of the decisions made to meet FPL's need in 2007. Unless these costs are reflected in the evaluation the result could lead to the selection of an alternative that would not be the most cost-effective choice.

As FPL performs more of these evaluations, it continues to enhance and refine its ability to identify and quantify all cost components. In addition, FPL's system does not remain static. Growth in demand and the effect of capacity additions to meet that demand have a significant effect on FPL's system. Therefore, the evaluation process must continue to evolve to ensure that the selected alternative is in fact the most cost-effective for FPL's customers.

The calculation of capacity and energy losses that has been a part of this effort represents one of those enhancements. These and the quantification of increased system operating costs are explained in detail by Mr. Reppen.

Q. Were any of the non-complying proposals eventually revised as necessary to comply with all minimum requirements?

A. No. The three non-complying proposers did not make the changes necessary to achieve compliance with all minimum requirements. In fact, each of these proposers failed to comply with at least three minimum requirements, as shown in Document RS-4. Therefore, FPL notified these three proposers in December that their four proposals would not be considered further.

The question of non-compliance with minimum requirements in this RFP became moot, however, because as shown in Document RS-3, the costs associated with those non-complying proposals were $276 million CPVRR or more greater than the costs of Turkey Point Unit 5.

Q. Please explain the results of FPL's non-economic evaluation.

A. A non-economic review was conducted to identify and, if necessary, address the risk exposure presented by portfolios that included complying proposals submitted in response to FPL's RFP and to compare such risk exposure to that of FPL's NPGU. This step sought to identify major issues of concern related to environmental, technical/operational and project execution factors.

The environmental review evaluated, for each alternative, the likelihood of successfully attaining the necessary permits, licenses and regulatory approvals within the time frame necessary to meet the in-service date of June 1, 2007. The experience of the proposer and that of FPL was considered, along with the specific characteristics of each alternative.

The technical/operational review evaluated factors such as the technology to be used for each alternative, and the design limitations and projected rating of the equipment.

The project execution review was applied only to the complying proposal because it considered exceptions taken by the proposer to provisions in the RFP and terms in the draft power purchase agreement attached to the RFP. The objective of this evaluation was to ascertain the likelihood of the proposer and FPL reaching a mutually acceptable contract.

The conclusion of the non-economic evaluation was that both the alternative portfolio consisting of the complying proposal and FPL's alternative generating unit, and Turkey Point Unit 5 reflected experience in permitting, building and operating gas generation facilities in Florida, using a mature, proven technology. Therefore, both offered a stable, acceptable risk profile and no additional investigation was required.

Q. Did FPL select a finalist as part of the RFP evaluation process?

A. Yes. The proposal that met all minimum requirements was, along with FPL's alternative generating unit (CT option), part of a portfolio which held the next highest economic ranking after FPL's NPGU. In addition, the results of FPL's non-economic evaluation indicated that this proposal offered a stable and acceptable risk profile. Consequently, this proposal was identified in December 2003 as the "finalist," and the proposer was invited to submit a "best and final offer."

Q. The Bid Rule permits the utility to change its cost estimates during an RFP and provide any remaining proposers the opportunity to revise their proposals as well. Did FPL revise its cost estimates during the RFP?

A. No, but FPL did allow the proposer selected as finalist to modify its bid in submitting its best and final offer. That finalist elected to increase its price as part of its best and final offer. This change increased the cost difference between Turkey Point Unit 5 and the closest alternative to $271 million, CPVRR. The final results of FPL's economic evaluation, showing Turkey Point Unit 5 and the alternative portfolio selected as "finalist" is provided in Document RS-5.

Q. In conducting its RFP evaluation, did FPL follow the methodology set forth in the RFP?

A. Yes. However, there were some modest adjustments made that were not material and had no effect on the outcome of the evaluations. In fact, the adjustments were favorable to the proposers. Furthermore, knowing that FPL would make these process adjustments would not have helped proposers develop more competitive proposals

For example, FPL indicated in the RFP that it would complete the initial screening of proposals and that any proposal that did not meet all minimum requirements would not be considered in the economic evaluation. However, to allow for proposers who did not initially meet minimum requirements to make the changes required to comply while at the same time avoiding delays in the evaluation process, we conducted the economic analysis of the seven portfolios that offered alternatives to FPL's NPGU before the question of proposal compliance was finally resolved.

Also, FPL indicated in the RFP that it would first rank individual proposals as a way to organize and prioritize the work of constructing the portfolios. However, in this instance we proceeded directly to include all proposals in the initial construction of portfolios. Once again, this adjustment had no impact on the proposers.

Yet another example was the consideration of upstream pipeline costs. FPL indicated in the RFP that it would develop estimates for the cost of upstream gas pipeline enhancements, if any, above those submitted in the proposals. For Turkey Point Unit 5 all pipeline costs were included in the analysis. For four of the alternative portfolios considered, there were no additional upstream gas pipeline enhancement costs above those included in the analysis. For the three other portfolios, studies to determine the cost, if any, of upstream pipeline enhancements would be done last. However, because these portfolios already were more than $270 million more costly than Turkey Point Unit 5, and because any additional costs attributed to these portfolios would only serve to increase the already sizable economic advantage of Turkey Point Unit 5, it became pointless to perform the additional studies.

VI. Turkey Point Unit 5 is FPL's Best, Most Cost-Effective Alternative to Meet FPL's 2007 Resource Need.

Q. Why do you believe Turkey Point Unit 5 is FPL's best, most cost-effective option to meet FPL's capacity need in 2007?

A. For the reasons I and other witnesses have presented, the Turkey Point Unit 5 project is the best, most cost-effective alternative to meet the capacity and energy needs of FPL's customers in 2007. This project is needed to maintain system reliability in 2007 as measured by FPL's 20 percent reserve margin criterion, and it will provide FPL's customers with an adequate supply of electricity at a reasonable cost.

The economic evaluations performed by FPL concluded that adding Turkey Point Unit 5 is more than $270 million less costly than any competing alternative. A separate analysis performed by an independent evaluator concluded that adding Turkey Point Unit 5 is more than $300 million less costly than any alternative.

The non-economic evaluation concluded that FPL's experience in permitting, building and operating combined cycle facilities in Florida, and the maturity of the technology proposed by FPL for Turkey Point Unit 5 result in a low, acceptable level of risk, at least as low as that for the next most economic portfolio. In addition, Turkey Point Unit 5 provides a very significant benefit because it improves the balance between demand and installed capacity in Southeast Florida.

FPL's Turkey Point Unit 5 project meets all of the criteria required by the Commission as the best and most cost-effective alternative available to FPL to meet its 2007 capacity need and should be granted a determination of need.

VII. Adverse Consequences if a Determination of Need for Turkey Point Unit 5 were not granted.

Q. Would there be any adverse consequences to FPL and its customers if the Commission were not to grant an affirmative determination of need for Turkey Point Unit No. 5?

A. Yes. If Turkey Point Unit 5 is not added, there are a number of adverse consequences that FPL's customers will face. If Turkey Point Unit 5 is not placed in-service by June 1, 2007 and FPL makes no alternative arrangement to obtain the additional capacity required to meet its 20 percent reserve margin reliability criterion in 2007, then FPL's customers would be served by a far less reliable system than either the Commission or FPL have identified as appropriate. If Turkey Point Unit 5 is delayed a year or not built at all, and FPL obtains alternative generation capacity to meet its 20 percent reserve margin criterion, the incremental cost to FPL's customers would be at least $86 million and $271 million, CPVRR, respectively.

Q. What is the impact on FPL's reserve margin of not placing Turkey Point Unit 5 in-service by June 1, 2007?

A. The addition of Turkey Point Unit 5 will increase FPL's system capability by 1,144 MWs for the summer of 2007, enabling FPL to achieve a reserve margin of 20.4 percent. Without the addition of Turkey Point Unit 5, FPL's reserve margin would decrease to only 14.7 percent for the summer of 2007.

As a result, FPL's customers would have a far less reliable system to serve them. Also, it should be noted that since demand on FPL's system is projected to grow at an average rate of about 500 MWs per year, not meeting the reserve margin criterion in 2007 will add to the challenge of economically adding sufficient capacity to meet reliability standards in subsequent years.

Q. What is the effect of denying need determination for Turkey Point Unit 5 on the cost of electricity?

A. If a need determination for Turkey Point Unit 5 were to be denied, FPL's customers would incur greater costs for electricity. The results of FPL's evaluation of 25 self-build alternatives and 7 alternative portfolios considered as part of the RFP process show that the addition of Turkey Point Unit 5 by June of 2007 is the most cost-effective alternative available to meet the 2007 need. Therefore, if Turkey Point Unit 5 is not built, the capacity and energy Turkey Point Unit 5 is expected to provide would have to be replaced with a higher-cost generation portfolio that would include a higher-cost FPL option and higher-cost power purchases and which would lead to increased operation of less efficient existing FPL units.

One measure of the incremental cost to FPL's customers caused by denial of a need determination for Turkey Point Unit 5 is provided by the results of FPL's evaluation of proposals submitted in response to the RFP. Based on those results, the next best alternative that is available to FPL would cost FPL's customers at least $271 million CPVRR more than Turkey Point Unit 5. This increased cost to FPL's customers cannot be justified.

If Turkey Point Unit 5 were to be delayed for one year to 2008, significant additional costs would also be incurred by FPL's customers. These costs would be both generation-related and transmission-related.

In regard to generation-related costs, several factors must be assessed. First, if a one year delay were to occur, FPL assumes that it would attempt to secure a one-year purchase of capacity for its 1,066 MW capacity need. Assuming (perhaps optimistically) that such a large, short-term purchase could be made, FPL estimates that the purchase cost would be at approximately $5/kW-month for a 2007 total of about $64 million (nominal) or approximately $47 million CPVRR. Second, a one-year delay in building Turkey Point Unit 5 would result in increased construction-related costs. It is difficult to determine the impact on construction-related costs due to the fact that there are numerous major equipment contracts, materials pricing issues and labor market cost uncertainties involved. However, even if the construction-related effects of a delay were conservatively assigned a zero cost and FPL merely escalated the current cost estimate for Turkey Point Unit 5, that would result in at least a $10 million increase in total construction costs. Finally, there would be higher fuel costs in 2007 from not having this fuel-efficient unit in-service in that year, and a reduction in capital costs in 2007 due to not building Turkey Point

Unit 5 in that year. FPL estimates that the net impact of all these generation-related cost impacts for one year is approximately $24 million CPVRR.

In regard to transmission-related cost impacts, there would be both transmission integration costs and a one-year cost of losses that would be incurred in connection with the 2007 purchases. Using the next lowest cost portfolio in the RFP as a basis for estimating these costs, this would add $56 million CPVRR for integration and $6 million CPVRR for losses, for a total of $62 million CPVRR for transmission-related costs.

Consequently, FPL estimates that the total costs to FPL's customers of a one-year delay in Turkey Point Unit 5 to be at least $86 million. This increased cost to FPL's customers cannot be justified.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF STEVEN R. SIM

DOCKET NO _______ - EI

MARCH 8, 2004

Q. Please state your name and business address.

A. My name is Steven R. Sim, and my business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. By whom are you employed and what position do you hold?

A. I am employed by Florida Power & Light Company (FPL) as a Supervisor in the Resource Assessment & Planning Business Unit.

Q. Please describe your duties and responsibilities in that position.

A. I supervise a group that is responsible for determining the magnitude and timing of FPL's resource needs and then developing the integrated resource plan with which FPL will meet those resource needs.

Q. Please describe your education and professional experience.

A. I graduated from the University of Miami (Florida) with a Bachelor's degree in Mathematics in 1973. I subsequently earned a Master's degree in Mathematics from the University of Miami (Florida) in 1975 and a Doctorate in Environmental Science and Engineering from the University of California at Los Angeles (UCLA) in 1979.

While completing my degree program at UCLA, I was also employed full-time as a Research Associate at the Florida Solar Energy Center during 1977-1979. My responsibilities at the Florida Solar Energy Center included an evaluation of Florida consumers' experiences with solar water heaters and an analysis of potential renewable resources including photovoltaics, biomass, wind power, etc., applicable in the southeastern United States.

In 1979 I joined FPL. From 1979 until 1991 I worked in various departments including Marketing, Energy Management Research, and Load Management, where my responsibilities concerned the development, monitoring, and cost-effectiveness of demand side management (DSM) programs. In 1991 I joined my current department, then named the System Planning Department, as a Supervisor whose responsibilities included the cost-effectiveness analyses of a variety of individual supply and DSM options. In 1993 I assumed my present position.

Q. Are you sponsoring an exhibit in this case?

A. Yes. It consists of the following documents:

SRS-1, Projection of FPL's 2007 Capacity Need;

SRS-2, FPL's Commission-Approved DSM Goals;

SRS-3, Summary of FPL Self-Build Options Considered;

SRS-4, Summary of Evaluation of FPL Construction Options to Meet 2007 Need: Top 5 Options;

SRS-5, List of Organizations Submitting Proposals;

SRS-6, Summary of Proposals;

SRS-7, Summary of Portfolios Evaluated;

SRS-8, FPL Rankings of Portfolios - EGEAS Costs Only;

SRS-9, FPL Rankings of Portfolios - EGEAS & Transmission-Related Costs Only;

SRS-10, Calculation of Peak Hour Loss Cost for the FPL 4 CT & Proposal 4 Portfolio;

SRS-11, Calculation of Annual Energy Loss Cost for the FPL 4 CT & Proposal 4 Portfolio;

SRS–12, FPL Rankings of Portfolios Prior to Short List Announcement - All Costs;

SRS-13, FPL Final Rankings of Portfolios After Best and Final Offer from Short List Proposer

Q. Are you sponsoring any sections in the Need Study document?

A. Yes. I am sponsoring Sections IV and VII and co-sponsoring Sections VI and VIII of the Need Study document. I also sponsor Appendices M, P, C-1, C-2, C-3, and C-4, and co-sponsor Appendices C and C-5.

Q. What is the purpose and scope of your testimony?

A. My testimony has seven main points. First, I discuss FPL's resource planning process. Second, I identify FPL's additional resource need for 2007 and explain how this need was determined. Third, I discuss FPL's demand side management (DSM) efforts and why DSM cannot reasonably be expected to meet the 2007 resource need. Fourth, I discuss the selection of the "next planned generating unit" presented in the RFP. Fifth, I present the proposals that FPL received in response to the RFP. Sixth, I explain the process FPL used in analyzing the economics of the RFP proposals and FPL construction options. Seventh, I present the results of these analyses.

I. FPL's Resource Planning Process

Q. What is the objective of FPL's resource planning process?

A. FPL's integrated resource planning (IRP) process was developed in the early 1990s and has been used since that time to determine three things: 1) when new resources are needed, 2) the magnitude (MW) of the needed resources, and 3) the type of resources that should be added. The type of resources that should be added is primarily based on a determination of the resources that result in the lowest average electric rates for FPL's customers. (It should be noted that when only power plants or power purchases are the resources in question, the determination can be made on the basis of lowest total costs. The lowest total cost perspective in these cases is the same as the lowest average electric rate perspective, since the number of kilowatt-hours over which the costs are distributed does not change, as would be the case when demand side management resources are being examined.)

Q. Please provide an overview of this resource planning process.

A. The IRP process has four main tasks. These four tasks are as follows:

Task 1: Determine the magnitude and timing of FPL's new resource needs.

- Task 2: Identify the resource options and resource plans that are available to meet the determined magnitude and timing of FPL's resource needs (i.e., identify the available competing options and resource plans).
- Task 3: Determine the economics for the total utility system with each of the eligible competing options and resource plans.
- Task 4: Select a resource plan from which FPL management will commit, as needed, to near-term options.

As previously mentioned, FPL has used this basic resource planning approach for its major resource decisions since the early 1990s.

Q. Was this resource planning approach also used for the RFP evaluation?

A. Yes. The IRP process outlined above describes the basic approach that FPL takes in its major resource planning efforts. Two examples of such efforts are analyses performed to identify FPL's best construction option for a particular year and evaluations associated with an RFP.

In regard to the current RFP, each of the four tasks outlined above was performed. FPL first determined the timing and magnitude of its 2007 resource need. Then it determined which resource options, both self-build and RFP proposals, were available to meet those needs and, using the available options, developed competing resource plans or "portfolios" of the available resource options with which to address the resource need. The economics of these competing portfolios then were determined, and a decision was made as to the best portfolio for FPL's customers.

II. FPL's Resource Need for 2007

Q. How did FPL decide it needed additional resources for 2007, and what was the magnitude of this resource need?

A. FPL uses two analytical approaches in its reliability analyses to determine the timing and magnitude of its future resource needs. The first approach is to project reserve margins both for Winter and Summer peak hours for future years. A minimum reserve margin criterion of 15 percent is used to judge the projected reserve margins through the Winter of 2004. Then, starting with the projected reserve margin for the Summer of 2004, and for all projected Winter and Summer reserve margins for subsequent years, the minimum criterion increases to 20 percent. This increase in the reserve margin criterion is due to a Commission-approved stipulation in FPSC Docket No. 981890-EU that included FPL.

The second approach is a Loss-of-Load-Probability (LOLP) evaluation. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to the reserve margin approach, the LOLP approach looks at the daily peak demands for each year, while taking into consideration the probability of individual generators being out of service due to scheduled maintenance or forced outages. LOLP is typically expressed in units of "numbers of times per year" that the system demand could not be served. FPL's LOLP criterion is a maximum of 0.1 days per year. This LOLP criterion is generally accepted throughout the electric utility industry.

For a number of years now, FPL's projected need for additional resources has been driven by the Summer reserve margin criterion. In other words, the Summer reserve margin criterion is projected to be violated before either the Winter reserve margin or LOLP criterion is violated. This again was the case in FPL's reliability analysis that was the basis for FPL's projected 2007 capacity need. Additional MW are needed to meet the 2007 Summer reserve margin criterion of 20 percent. The additional MW needed by the Summer of 2007 are projected to be 1,066 MW if the resource is to be provided by a supply side option (i.e., power plant construction or purchase) or, due to the 20 percent reserve margin criterion, 888 MW (1,066 MW/1.20 = 888 MW) if provided by a DSM-based reduction to the forecasted peak load. This projection of a 1,066 MW need for the Summer of 2007 is shown in Document SRS-1, which also shows that no capacity addition would be needed based on the Winter reserve margin criterion. This projection relies upon FPL's load forecast that is addressed by Dr. Leo Green in his testimony.

III. Demand Side Management

Q. When did FPL begin its DSM efforts, and how have they progressed over time?

A. FPL has a long history of identifying, developing and implementing DSM resources to avoid or defer the construction of new power plants. FPL first began offering DSM programs in the late 1970s with the introduction of its Watt-Wise Home Program. An increasing number of additional DSM programs were offered throughout the 1980s and 1990s. These programs have included both conservation and load management programs, targeting the residential, commercial and industrial markets.

FPL's portfolio of DSM programs has evolved over time. FPL continually looks for new DSM opportunities in its research and development activities. When a new DSM opportunity is identified and projected to be cost-effective, FPL attempts either to implement a new DSM program or to incorporate this DSM opportunity into one or more of its existing DSM programs. In addition, FPL has modified DSM programs over time in order to maintain the cost-effectiveness of the programs. This allows FPL to continue to offer the most cost-effective programs available. On occasion, FPL also has terminated DSM programs that were no longer cost-effective and could not be modified to become cost-effective.

Q. How effective has FPL been in implementing DSM, and what are the resulting impacts of these efforts?

A. FPL has been very successful in cost-effectively avoiding new power plant construction using DSM. Since the inception of its programs through the end of 2003, FPL has achieved 3,270 MW (at the generator) of Summer peak demand reduction, 2,604 MW (at the generator) of Winter peak demand reduction, and 25,429 GWh (at the generator) of energy savings. FPL has also completed more than 1,900,000 energy audits of customers' homes and facilities.

This amount of peak demand reduction has eliminated the need for the equivalent of 10 power plants of 400 MW capacity each (after including the impacts for reserve margin requirements). Most importantly, FPL has achieved this level of demand reduction without penalizing customers who are non-participants in its DSM programs. FPL has been able to avoid penalizing non-participating customers by offering only DSM programs that reduce electric rates for all customers, DSM participants and non-participants alike.

Q. How do FPL's DSM efforts compare to those of other utilities?

A. The U.S. Department of Energy (DOE) reports on the effectiveness of utility DSM efforts through its Energy Information Administration. DOE separately measures both conservation and load management. Based on the most current comparative data available, which is for the year 2001, FPL is ranked number one nationally for cumulative conservation achievement and number five in load management.

Another important indication of the success of DSM in Florida and FPL's service territory was the outcome of a benchmarking study conducted by the State of Florida Energy Office in 1992, entitled "Electricity Conservation and Energy Efficiency in Florida." That study found that since the early 1980s, FPL had been actively involved in DSM programs and had been an industry leader in DSM application. It further found that: "The Florida utilities have been extremely successful in reducing peak capacity requirements. The Florida utility peak capacity savings are generally higher than those obtained by other utilities. While the Florida utilities have been focusing their efforts on load management, they have been among the leaders in achieving energy savings."

Q. What are FPL's current DSM goals?

A. Document SRS-2 shows FPL's current DSM goals that were approved by the Commission in Order No. PSC-99-1942-FOF-EG. As shown in this document, FPL's DSM Goals are 765 MW (Summer MW at the meter) through 2009. This determination was made based upon a comprehensive analysis.

Q. Has FPL continued to refine and improve its DSM programs?

A. Yes, since implementing its latest DSM Plan in 2000, FPL has made changes to existing programs. These include revising incentive schedules for several programs as well as enhancing eligibility requirements to encourage additional participation and the addition of new measures.

Q. Has FPL continued to look for new DSM opportunities?

A. Yes. Historically, FPL has performed extensive DSM research and development. FPL has continued such activities not only through its Conservation Research and Development Program, but also through individual research projects. These efforts examine a wide variety of technologies, which build on prior FPL research, where applicable, and will expand the research to new and promising technologies as they emerge.

Q. Could FPL have met its resource need for 2007 with DSM?

A. No. FPL's 2007 resource need already reflects all of the reasonably achievable, cost-effective level of DSM for FPL between 2000 and 2007 (625 MW at the meter) as determined in FPL's Commission-approved DSM Goals. In other words, FPL's analysis already has captured the cost-effective DSM available on FPL's system and determined that FPL still needed additional capacity resources.

If the 2007 resource need were to be met solely by additional new DSM resources, FPL would need to find an additional 888 MW of cost-effective DSM to meet the 2007 resource need. (After accounting for FPL's 20 percent reserve margin criterion, the 1,066 capacity need is reduced to 1,066 MW/1.20 = 888 MW.) It is unrealistic to conclude that FPL could implement sufficient new DSM programs in the next three years (mid-2004 to mid-2007) to meet this need.

The Commission previously determined that there was only 765 MW of additional, achievable, cost-effective DSM for the entire ten-year period of 2000-2009. Therefore, it is not reasonable to conclude that FPL could achieve an additional 888 MW of cost-effective DSM in the next three years. This is particularly so given that it would take some time to secure Commission approval to proceed with new DSM programs or to modify existing programs. In fact, the time needed for FPL to prepare needed filings and secure this approval would likely reduce the available time to implement additional DSM from 3 years to 2½ years. So, even if there were cost-effective DSM potential out there not previously found by FPL or the Commission, not enough could be added in the time remaining to meet FPL's 2007 resource needs.

Consequently, cost-effective DSM could not meet the 2007 resource need. This need must be met by capacity (construction and/or purchase) options.

IV. The Selection of FPL's "Next Planned Generating Unit"

Q. Did FPL consider other power plant construction options before designating the Turkey Point combined cycle unit as its "next planned generating unit"?

A. Yes. More than two dozen combustion turbine (CT) and combined cycle (CC) options were considered in FPL's efforts to determine its best construction option for meeting the 2007 need. Included in these options were various configurations of both CT and CC units at a number of sites. Document SRS-3 summarizes the self-build options FPL initially considered.

Q. Please describe the analytical approach FPL used to determine its best construction option.

A. In its efforts to evaluate the construction options, FPL first identified the construction options that could be permitted and built in time to begin service by mid-2007. For those options that met this criterion, portfolios of one or more construction options were developed that met the 2007 capacity need. For each portfolio, FPL evaluated the capital and O&M costs, plus the system fuel costs and costs associated with meeting subsequent years' resource needs, in a multi-year expansion plan approach using its Electric Generation Expansion and Analysis System (EGEAS) model. FPL then combined those results with the results of an analysis of the transmission-related costs and impacts of siting generation both within and outside of Southeast Florida. In this way, FPL sought to identify the portfolio whose combination of construction option type(s) and site(s) was the best FPL choice, based on total economics (i.e., generation costs, system fuel costs, and transmission-related costs).

For its analysis of transmission-related costs for each portfolio, the portfolio's component capacity option(s), including the site(s) on which the option(s) was located, was examined. FPL first evaluated the transmission interconnection and integration requirements and costs for the portfolio. These costs then were combined with the cost of transmission losses associated with the portfolio. The transmission loss approach first developed MW loss values both for peak hour and average load periods, converted the peak and average load (MW) losses to annual energy (MWH) loss values, then assigned a dollar cost to both the MW and MWH losses.

Q. Was the analytical approach used to determine FPL's best construction option similar to the economic evaluation process FPL later utilized to examine responses to its RFP?

A. Yes. Most of the analyses used to determine FPL's "next planned generating unit" (i.e., the EGEAS analyses and the transmission interconnection and integration cost calculations) were essentially identical to the analyses later used to evaluate RFP responses. The remaining part of the analysis, the evaluation of the cost of transmission losses, was similar in basic concept to that used in the evaluation of transmission loss costs during the RFP analyses. The calculation process ultimately used in this analysis to determine the cost of losses was subsequently further refined prior to issuance of the RFP.

Q. Were there any other differences in the evaluation approach used in determining FPL's best construction option compared to the evaluation approach used in the RFP economic evaluations?

A. Yes. There was one cost calculation that was used in the RFP evaluation work that was not used in the work carried out to determine FPL's best construction option. This calculation of increased operating costs from operating FPL's Southeast Florida gas turbines out of economic dispatch is due to generation/load imbalance in the region. At the time the analyses to determine the best construction option were being conducted, FPL was working on an approach to capture these increased operating costs but did not complete this work in time to utilize the approach in these analyses.

Q. If this "additional" cost calculation used in the RFP evaluations had been included in the work to determine FPL's best construction option, would a different FPL construction option have emerged as the best choice?

A. No. As will be discussed below, the top two construction options were 4x1 CC units, one located within the Southeast Florida region and one located just north of that region. In regard to increased operating costs, the inclusion of these costs would have favored the CC option located in Southeast Florida in comparison to the CC option located just outside of that region. However, because the CC option located in Southeast Florida already had been selected as the best FPL construction option without consideration of the increased operating costs, including these costs would only have reinforced its selection as the best construction option.

Q. Was the impact of the construction options on FPL's capital structure considered in this analysis of construction options?

A. Yes. FPL considers the impact of all resource additions on FPL's capital structure, whether they are FPL self-build options or non-FPL options. In considering FPL self-build options, such as in the evaluation of construction options to meet the 2007 capacity need, FPL uses a 55 percent equity / 45 percent debt incremental capital structure; therefore, self-build capacity additions will have no impact on FPL's target adjusted capital structure of 55 percent equity / 45 percent debt.

Q. Please briefly describe the results of the analyses to determine the best construction option for FPL.

A. The analyses yielded several results. First, the 4x1 CC options were more economical than the 2x1 CC's. This result was consistent with results from resource planning analyses in prior years. Second, when considering only generation-related costs captured in the EGEAS model work, a 4x1 CC sited at FPL's Martin site emerged as the leading candidate. Third, after all of the transmission-related costs for interconnection, integration, and losses were added to the generation-related costs, a 4x1 CC unit located at FPL's Turkey Point site emerged as the most economical alternative.

The results of this evaluation of FPL construction options to meet the 2007 need are summarized on Document SRS-4, which presents the evaluation results for the top 5 options considered. Based upon its evaluation, FPL selected the Turkey Point CC unit (Turkey Point Unit 5) as its best, most economical construction option and designated Turkey Point Unit 5 as the next planned generating unit in the RFP.

Q. In its RFP, FPL presented not only Turkey Point Unit 5 as its next planned generating unit, but also an "alternative generating unit." Why did FPL also present an alternative generating unit of a 4x0 CT in its RFP?

A. As explained in its RFP, pages 7 and 8, FPL went beyond the requirements of Rule 25-22.082, Florida Administrative Code (the Bid Rule) and presented this alternative generating unit of 4 CTs at Turkey Point for several reasons. First and foremost, this option increased the number of possible portfolios of capacity options that could be created and still include a significant amount of generation in Southeast Florida that would help address the load/generation imbalance concern in that region. Second, it provided potential proposers with a known-in-advance portfolio "pairing partner" for entities considering proposals that could only partially meet the 2007 need requirement. Third, it allowed FPL flexibility to address unexpected developments that might have occurred (such as significant changes in the load forecast) during the RFP evaluation process.

As will be discussed later, the Turkey Point 4 CT option was useful in creating additional portfolios for consideration, and those portfolios contained a substantial number of MW in Southeast Florida. The inclusion of this alternative generating unit, which was not required, actually worked to the benefit of several proposals by allowing them to be included in portfolios that could meet the required 1,066 MW need.

IV. The RFP Proposals

Q. Please provide a general description of the proposals that FPL received in response to the RFP.

A. FPL received 5 proposals from 4 organizations (proposers). A listing of the organizations that submitted proposals is presented in Document SRS-5. This document also lists the types of proposals submitted and whether the proposals were based on a new or existing generating source. All proposals were power purchase offerings, with four proposals being natural gas-based and one proposal being coal-based. Three proposals were based on combined cycle technology, one proposal was based on combustion turbine technology, and one proposal was based on circulating fluidized bed (CFB) technology. More detailed information regarding the proposals is presented in Document SRS-6.

Q. Did all of the proposals clearly provide the information FPL requested for its evaluations and meet the RFP Minimum Requirements, so that FPL could immediately begin its evaluations?

A. No. FPL and an independent evaluator, Alan Taylor of Sedway Consulting, reviewed all proposals received on the Proposal Due Date of October 24, 2003. Questions regarding whether or not RFP Minimum Requirements had been met were immediately raised after the initial review of the proposals. In addition, certain information requested on the RFP forms was either omitted or needed clarification. Issues regarding omitted or confusing information were brought to the proposers' attention and were resolved relatively quickly.

However, issues regarding whether proposals complied with the RFP Minimum Requirements were not resolved as quickly. Mr. Silva discusses in his testimony that four of the five proposals ultimately did not comply with the RFP Minimum Requirements after FPL's efforts to encourage the proposers of these proposals to meet the RFP Minimum Requirements were unsuccessful.

V. Overview of the RFP Economic Evaluation Process

Q. What was the general approach used in the RFP economic evaluation work?

A. FPL conducted its own evaluation of all of the proposals, the FPL alternative generating unit, and the next planned generating unit, Turkey Point Unit 5. In addition, separate analyses of these options were performed by an independent evaluator, Mr. Alan Taylor of Sedway Consulting, Inc (Sedway). Mr. Taylor's testimony addresses Sedway's analysis; I will focus on FPL's evaluation.

FPL first ensured that its economic analyses of the proposals were "blind" by providing code numbers to the proposals. FPL adopted the convention of coding the proposals as Bid 1, Bid 2, etc. for FPL's and Sedway's economic evaluation work as is shown in the Confidential Appendices. However, the proposals are referred to as Proposal 1, Proposal 2, etc. throughout FPL's Need filing.

Using the coding, the analyses of the proposals were conducted without organizational names attached to the proposals. FPL's alternative generating unit and Turkey Point Unit 5 could not be evaluated "blind," because these two options were listed in the RFP document and, therefore, were easily recognizable.

FPL then used what I will describe as a four-step evaluation approach to determine the economics of the proposals, consistent with the evaluation framework described in the RFP. The approach is based on creating capacity multi-year expansion plans that utilize the proposals only, Turkey Point Unit 5 only, or a combination of RFP proposals and FPL's alternative generating unit to meet FPL's 2007 capacity need. For 2008 and beyond, greenfield "filler" units are added to the expansion plan as needed to maintain FPL's reserve margin.

As previously mentioned, FPL used the EGEAS model in these analyses. This model was designed by Stone & Webster for the Electric Power Research Institute (EPRI) some years ago, and FPL has used it since its development.

The EGEAS model and its results have been used for purposes of evaluations and analyses that have served as the basis for a host of decisions in previous Commission proceedings.

The four-step evaluation approach that FPL used can be summarized as follows:

Step 1: Determining Portfolios to Evaluate:

Two determinations were made in this step. The first determination was to identify the proposals that would be carried forward in the economic evaluation. The second determination was to identify the portfolios that would be created from these proposals, or from combinations of these proposals and FPL's alternative generating unit, for purposes of comparison to Turkey Point Unit 5.

Regarding the first determination, it was decided that FPL and Sedway would proceed with the economic evaluation including all proposals received pending resolution of questions regarding the proposers' compliance with the RFP Minimum Requirements.

The second determination was made by FPL with input from Mr. Taylor. Once these determinations had been made, the portfolios to be evaluated were transmitted to Mr. Taylor, who proceeded to conduct separate evaluations in parallel with FPL, as well as to Mr. Reppen and FPL transmission engineers working under his direction.

Step 2: The Separate Evaluations:

In Step 2, five separate evaluations were carried out largely in parallel.

a) FPL conducted an EGEAS-based evaluation that addressed the following system generation-related costs associated with each portfolio:

- capital or capacity costs;
- fixed O&M, variable O&M, and capital replacement costs;
- option and FPL system fuel/energy costs;
- transmission interconnection costs; and,
- gas pipeline lateral costs.

b) Mr. Taylor used Sedway's RSM model to also evaluate these same costs associated with each portfolio.

c) Mr. Reppen directed and led the evaluation of the following transmission-related costs and impacts of each portfolio:

- transmission integration costs;
- peak hour losses (MW) and average load losses (MW); and,
- increased operational costs.

d) FPL took the peak hour and average load losses (MW) results from Mr. Reppen, used these to develop annual energy losses (MWH), and assigned costs to both the MW and MWH loss values to develop portfolio-based costs of losses.

e) FPL developed net equity adjustment costs for each portfolio based upon the equity adjustment calculation and a calculation of offsetting mitigating factor values. Both aspects of the net equity adjustment calculation were performed consistently with the calculations described in the RFP.

Step 3: Combining the results of the separate evaluations carried out in Step 2.

The combination of the different types of costs developed in Step 2 provides a total cost picture of each portfolio. In essence, two total cost pictures for each portfolio were developed, one EGEAS-based picture (containing the EGEAS results, the transmission integration and increased operating costs, the cost of losses, and the net equity adjustment costs) and one RSM-based picture (in which the above-mentioned EGEAS results are replaced by the RSM results). FPL then used these two total cost pictures, along with the results of the non-economic evaluation discussed by Mr. Silva, to identify which, if any, proposals should be identified as finalists. Such proposals would then be asked to provide a Best and Final Offer which would be evaluated.

Step 4: Final cost determination after Best and Final Offer was received.

In this final step, the total cost for each portfolio that contained the finalist proposal was re-evaluated to incorporate that proposal's Best and Final Offer. This resulted in two final total cost pictures, one EGEAS-based and one RSM-based, for all portfolios.

Q. You mentioned above that "expansion plans" containing the portfolios were evaluated. Why is it appropriate to perform the economic evaluations based on multi-year expansion plan costs?

A. It is not only appropriate to do this, but also necessary if one is to capture and fairly compare all of the impacts the various options or portfolios designed to address FPL's capacity need for a specific year (in this case, for 2007) will have on FPL's system, and the resulting costs to be incurred by FPL's customers, over a longer time period. A multi-year expansion plan is designed to address FPL's capacity needs in years <u>after</u> the 2007 option or portfolio is placed in-service to capture the option's or portfolio's cost and impacts on FPL's system in later years.

For example, assume we are comparing Option A and Option B. Option A has a heat rate of 7,000 Btu/kWh and is offered to FPL for 15 years while Option B has an 8,000 Btu/kWh heat rate and is offered for 20 years. Evaluating these options from an expansion plan perspective allows one to capture the economic impacts of both the heat rate and term-of-service differences. The lower heat rate of Option A will allow it to be dispatched more than Option B, thus reducing the run time of FPL's existing units more than will Option B. This results in greater production cost savings for Option A. However, Option B's longer term-of-service means that it defers for a longer period the need for future generation. Therefore, Option B will get capacity avoidance benefits for more years.

Only by taking a multi-year expansion plan approach to the evaluation can factors such as these be captured and effectively compared. In the RFP economic evaluation, the expansion plans created addressed the FPL system through the year 2031.

Q. Are "filler" units needed in an expansion plan evaluation?

A. Yes. The "filler" units are needed in a multi-year expansion plan analysis to meet FPL's capacity needs for 2008 and beyond. In this way one can ensure that the expansion plans being compared all meet FPL's reliability criteria for each year in the analysis period, ensuring that the results of the comparison are meaningful.

Q. What type of "filler" units were assumed in the evaluation?

A. Two "types" of filler units were used: a complete or "full," 1,144 MW 4x1 CC unit and a scaled down 250 MW version of the larger CC unit that maintained the same $/kW cost structure and performance characteristics. Based on results of analyses carried out in preparation for the RFP evaluation, only one unit (either the full CC unit or the scaled down version) was the available filler unit option in EGEAS for each year in the 2008 - 2031 time frame. The full CC option was used to meet FPL's capacity needs for the 2008 – 2023 time frame, while the scaled down 250 MW version was used from 2024 – 2031.

FPL chose to use a scaled down version of the large CC unit for the later years for two reasons. First, the use of a smaller filler unit in the time frame from 2024 – 2031 would allow better consistency in the amount of total long-term system MW associated with each of the portfolios. Second, the use of a smaller filler unit avoids unduly penalizing portfolios for which one or more component capacity options' proposed term-of-service would end in the 2024 – 2031 time frame. FPL believed that adding the capital cost of the full-sized CC unit in those late years of the analysis period could unduly penalize such portfolios because there are not enough remaining years in the analysis period over which the fuel savings of the CC unit can overcome its capital costs. For these reasons, the scaled down version of the CC unit was used as the filler unit addition in the 2024 – 2031 time frame to meet FPL's reserve margin.

VI. The Results of the Analyses

Q. How did the eligibility of the proposals affect the economic evaluation?

A. Four of the five proposals ultimately were determined not to have met the RFP Minimum Requirements, and the corresponding proposers were notified that these proposals would not be considered further. Mr. Silva addresses that eligibility determination in his testimony.

However, before compliance with Minimum Requirements was finally determined, FPL decided that Sedway Consulting and FPL would conduct economic analyses of <u>all</u> proposals received. This decision was made primarily because FPL wanted to allow proposers every opportunity to revise their proposals and achieve compliance, but at the same time, FPL did not want to delay the evaluation process. It would take time to communicate with proposers to discuss - and, hopefully, correct - the aspects of the proposals that failed to meet Minimum Requirements. Waiting for this communication to be completed would have significantly delayed completion of the evaluation. Consequently, <u>all</u> proposals were included in the economic evaluation.

Q. How did FPL decide what portfolios would be evaluated alongside FPL's next planned generating unit in the economic evaluation?

A. The objective was to evaluate portfolios against FPL's next planned generating unit, Turkey Point Unit 5. Therefore, Turkey Point Unit 5 was one portfolio evaluated. FPL utilized its EGEAS model to create potential portfolios for consideration as alternatives to Turkey Point Unit 5 and decided on 7 alternative portfolios. Two other "single option" portfolios; Proposal 2 (1,220 MW) and Proposal 3 (1,220 MW), were identified. All other portfolios consisted of two or more capacity options (i.e., a combination of two or more proposals or a combination of FPL's alternative generating unit and one or more proposals). Five portfolios consisting of two or more capacity options, along with the two "single option" portfolios mentioned above were selected to be included in the evaluation alongside the portfolio consisting of Turkey Point Unit 5. Therefore, a total of eight portfolios were evaluated.

Document SRS-7 presents these 8 portfolios. These 8 portfolios then were utilized by FPL's Resource Assessment & Planning Business Unit for its EGEAS, costs of losses, and net equity adjustment evaluations; by Mr. Taylor for his RSM evaluation; and by Mr. Reppen for the transmission-related evaluation work. As previously mentioned, all of these work efforts proceeded in parallel.

Q. What were the EGEAS-based results of the evaluation of these 8 portfolios?

A. The results of the EGEAS analyses are presented in Document SRS-8. This document shows that Turkey Point Unit 5 emerged from the EGEAS analyses with a substantial cost advantage, $104 million cumulative present value of revenue requirements CPVRR, over the next most economic portfolio. This next most economic portfolio consisted of a combination of FPL's alternative generating unit, the Turkey Point 4 CT option, and Proposal 4. All of the remaining portfolios ranged from $121 to $197 million CPVRR more expensive than Turkey Point Unit 5.

Q. How did the results change after the inclusion of the transmission-related costs?

A. These results are presented in Document SRS-9. As previously discussed, the transmission-related costs include several different costs: 1) transmission integration costs, 2) the costs of peak hour losses, 3) the costs of annual energy losses (that are derived from the peak hour losses and the average load losses), and 4) increased operating costs. Mr. Reppen provided the transmission integration and increased operating costs, plus the peak hour losses (MW) and average load losses (MW).

The inclusion of these transmission-related costs resulted in two basic changes to the EGEAS-only results presented in Document SRS-8. First, the cost advantage of Turkey Point Unit 5 increased from $104 to $204 million, CPVRR. Second, the ranking order of the remaining portfolios changed, with the portfolio consisting of Proposal 3 and Proposal 1 now moving into the runner-up slot.

Q. You mentioned that FPL assigned costs to peak hour losses (MW) and annual energy (MWH) losses for each portfolio. How did FPL develop the costs that were assigned?

A. As discussed on page E-12 of Appendix E of FPL's RFP, FPL assigned an initial proxy purchase cost of $5/kw-month to the peak hour losses. This cost was assumed to begin in 2009 and to escalate at 1.7 percent per year. In assigning costs to annual energy losses, FPL first had to convert the peak hour losses (MW) and the average load losses (MW) provided by Mr. Reppen into annual energy losses (MWH) for all years in the analysis period.

The peak hour loss (MW) value for each portfolio was multiplied by 876 hours (FPL assumed 10 percent of the annual hours were on-peak) to obtain a peak hour energy loss (MWH). This value was multiplied by an on-peak marginal energy cost to obtain an on-peak energy loss cost. The average load loss (MW) value was multiplied by the remaining 7,884 annual hours to derive an off-peak energy loss (MWH). This value was multiplied by an off-peak marginal energy cost to obtain an off-peak energy loss cost. FPL used the fuel cost forecast supplied to prospective proposers to develop marginal fuel costs for both peak hours and off-peak hours.

The on-peak and off-peak annual energy loss costs were then summed to derive a total annual energy loss cost. Document SRS-10 and Document SRS-11, respectively, present the calculations of costs for the peak hour capacity losses and annual energy losses for the portfolio containing the FPL 4 CT option and Proposal 4. The proxy purchase and marginal energy cost values shown for this portfolio were used in evaluating all portfolios.

Q. Document SRS-9 shows that two cost components remain to be factored in: upstream gas pipeline costs and the net equity adjustment. How did the picture change when these two remaining cost components were added?

A. In regard to upstream gas pipeline costs, page 10 of FPL's RFP states that each natural gas-based proposal has to include all costs to build and maintain any pipeline lateral to the generating unit, and include "all capital costs associated with any interstate mainline improvements required to deliver the full fuel requirements, at the required pressure, to the Proposer-designated Fuel Delivery Point." In its economic evaluation, FPL assumed that every proposal complied with this requirement and included all proposal-specific gas pipeline costs.

The "upstream gas pipeline costs" component of the RFP economic evaluation was designed to address gas pipeline costs, different from those reflected in each individual proposal, that might occur if two or more gas-based capacity options were combined in a portfolio. Of the eight portfolios considered, five did <u>not</u> consist of multiple gas-fired units: Turkey Point Unit 5; Proposal 2; Proposal 3; Proposal 2 & Proposal 1; and Proposal 3 & Proposal 1. Consequently, for these five portfolios, the issue of upstream gas pipeline costs was not relevant; i.e., there were zero upstream gas pipeline costs for these five portfolios.

The determination of upstream gas pipeline costs for the three remaining portfolios that consisted of more than one gas-fired capacity option (FPL 4 CT & Proposal 4; FPL 4 CT & Proposal 4 & Proposal 1; and FPL 4 CT & Proposal 4 & Proposal 5) was to be addressed as one of the last steps in the economic evaluation. However, by the time FPL turned to address the upstream gas pipeline question for these three portfolios, the results of the other economic evaluation steps that had been completed clearly showed that these three remaining portfolios were <u>significantly</u> more expensive than Turkey Point Unit 5. Since the inclusion of upstream gas pipeline costs, if any, for these three portfolios would likely have <u>increased</u> this economic differential, and the review that would be needed to determine those costs would require additional time, FPL decided <u>not</u> to carry out the analysis to determine potential upstream gas pipeline costs for these three remaining portfolios. Instead, FPL chose to assign an upstream gas pipeline cost of zero for these remaining portfolios for purposes of the economic evaluation.

In regard to the net equity adjustment, seven of the eight portfolios resulted in the need for an equity adjustment because these portfolios contained one or more power purchase option. (The impact on FPL's capital structure for the eighth portfolio consisting of Turkey Point Unit 5 was already captured by assuming an incremental 55 percent equity / 45 percent debt investment in the new unit.) Consequently, a net equity adjustment value, derived by calculating an equity adjustment less mitigating factor values, was computed for each of these seven other portfolios that included at least one purchased power option. The calculations of the net equity adjustment value for each of these seven portfolios are presented in Appendix C-5 of the Need Study.

The results of including these upstream gas pipeline and net equity adjustment costs are presented on Document SRS-12. Once again, two basic changes to the previously presented results occurred. First, the economic advantage of Turkey Point Unit 5 increased further to $266 million CPVRR. Second, the ranking order of the remaining portfolios again changed with the portfolio consisting of the FPL 4 CT option and Proposal 4 returning to the runner-up slot.

Given that Proposal 4 was the only proposal that complied with all Minimum Requirements, that the runner-up portfolio consisted of the FPL 4 CT option and Proposal 4, and that the results of the non-economic evaluation did not adversely affect the viability of Proposal 4, FPL informed the proposer that offered Proposal 4 that it had made FPL's RFP Short List and requested a Best and Final Offer.

Q. **How were the net equity adjustment costs calculated?**

A. The two components of the net equity adjustment, the equity adjustment and mitigating factor values, were calculated following the process and using the formulae presented in Appendix C of FPL's RFP.

In regard to the equity adjustment calculation, the methodology was presented on page C-7 of the RFP document. On that page, the equity adjustment value for a hypothetical purchase of 500 MW with a constant $7/kw-month capacity payment was calculated. In evaluating the proposals received in response to the RFP, FPL input the proposed capacity amount and annual capacity payments into the spreadsheet to develop the equity adjustment value for each proposal.

The mitigating factor methodology was explained in detail on pages C-3 through C-6 of the RFP document. In addition, a calculation of the mitigating factor values was also presented on page C-8 of the RFP document using the same hypothetical purchase of 500 MW used in the equity adjustment example calculation. In this example, the hypothetical capacity amount was multiplied by the sum of the dollar amounts for the Completion Security mitigating factor ($526/MW) and for the Performance Security mitigating factor ($2,014/MW).

In evaluating the proposals received in response to the RFP, FPL input the proposed capacity amount into this formula to develop the total mitigation factor value for each proposal. This total mitigation factor value was then subtracted from the equity adjustment value to derive a net equity adjustment value for each proposal. The results of the equity adjustment and mitigating factor calculations for each proposal and each portfolio are presented in Confidential Appendix C-5.

Q. The Bid Rule allows FPL to change its cost estimate during the RFP as long as the remaining proposers are given the opportunity to revise their proposals. Did FPL change the cost estimate for its next planned generating unit at any time during the RFP?

A. No.

Q. How did the values shown in Document SRS –12 change after the Best and Final Offer for Proposal 4 was received?

A. The Best and Final Offer increased the overall cost (i.e., capacity payment and equity adjustment) for Proposal 4 by approximately $5 million CPVRR, with no changes to other aspects of the proposal. Therefore, the cost of the three portfolios that contained Proposal 4 all increased by approximately $5 million CPVRR as is shown in Document SRS-13.

Q. Please summarize your testimony.

A. FPL's 2003 resource planning work determined that FPL had a need for additional resources in 2007. In order to meet FPL's Summer reserve margin criterion of 20 percent for that year, FPL needed 1,066 MW if the resource need was to be filled by new supply (power plant construction and/or purchase) or 888 MW if the resource need was to be filled by new DSM. The magnitude of this additional resource need was much too great to be met by new DSM, so the need would have to be met by one or more new supply options. Because the type of new power plant (a combined cycle unit) that FPL selected as its next planned generating unit to meet this need would require a determination of need, FPL issued an RFP for new capacity to meet this 2007 need.

Five proposals from four organizations were received in response to the RFP. Although four of the five proposals ultimately did not comply with the RFP Minimum Requirements, FPL decided in Step 1 of its economic evaluation process to consider all five proposals in its initial economic evaluation. FPL then utilized those five proposals and its alternative generating unit to develop seven portfolios of capacity options that were analyzed alongside an eighth portfolio consisting of Turkey Point Unit 5 during the remainder of the evaluation.

After three of the four steps in FPL's economic evaluation had been completed, Turkey Point Unit 5 emerged as the clear economic choice by being $266 million CPVRR less expensive than the runner-up portfolio that consisted of FPL's 4 CT option and Proposal 4. Based on the results of the economic and non-economic evaluations, Proposal 4 was named to the RFP Short List, and a Best and Final Offer was requested for Proposal 4.

Once Proposal 4's Best and Final Offer was received, FPL incorporated it in the last step of its economic evaluation process. The final EGEAS-based total cost picture showed that Turkey Point Unit 5 was the most economical choice by $271 million CPVRR over the runner-up plan. The results of Sedway's analysis also clearly showed Turkey Point Unit 5 to be the most economical choice. All other plans were even more expensive than the runner-up plan.

Therefore, the results of FPL's and Sedway's analyses show that FPL's Turkey Point Unit 5 is the most cost-effective alternative and the best choice for meeting FPL's 2007 capacity need.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF MORAY P. DEWHURST

DOCKET NO. _______ - EI

MARCH 8, 2004

Q. Please state your name and business address.

A. Moray P. Dewhurst, 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. What is your employment capacity?

A. I serve as Senior Vice President of Finance and Chief Financial Officer of Florida Power & Light Company (FPL or the Company).

Q. Please describe your educational and professional background and experience.

A. I have a bachelor's degree in Naval Architecture from MIT and a master's degree in Management, with a concentration in finance, from MIT's Sloan School of Management. I have approximately twenty years of experience consulting to Fortune 500 and equivalent companies in many different industries on matters of corporate and business strategy. Much of my work has involved financial strategy and financial re-structuring. I was appointed to my present position in July of 2001.

Q. What is the purpose and scope of your testimony?

A. My testimony addresses two main subjects relevant to FPL's Request for Proposals issued August 25, 2003 (RFP) and the selection of FPL's Turkey Point combined cycle option as the most cost effective project to meet resource needs in 2007. First, I describe the state of the independent power industry generally, and the need to ensure that proposers meet certain minimum standards of financial viability. I also discuss the importance of a potential supplier being willing and able to make the necessary business commitments to ensure that a proposed plant will be completed in a timely manner and operated over the term of the agreement in accordance with the supplier's original promises. I explain how these factors were taken into consideration in the RFP process.

Second, my testimony supports and supplements the testimony of Dr. Avera regarding: (a) the propriety of assigning an equity adjustment to the costs of non-FPL bids submitted in response to FPL's RFP when comparing those bids to FPL's self-build option; (b) the methodology employed in computing the amount of debt equivalent added to the Company's balance sheet; and (c) the assumptions underlying the amounts computed.

Q. Are you sponsoring any sections in the Need Study Document?

A. Yes. I am sponsoring the Financial and Economic Data included in Section V and Appendix G, Financial and Economic Assumptions, and co-sponsoring Appendix C-5.

Q. Are you sponsoring an exhibit?

A. Yes, I am sponsoring Exhibit No.___, Document No. MPD-1, which consists of Standard and Poor's (S&P) article: *Research: Energy Merchant Debt Prospects: When "Worst-Case" Scenarios Become the "Base Case"*, February 2, 2004.

Q. Describe the current state of the independent power producer (IPP) industry as it relates to capital markets.

A. On average, the trend in credit quality for the IPP segment of the U.S. utility industry has been negative for the past two years. However, there have been significant variations across companies. In general, companies that have over-extended and over-leveraged themselves, and/or those that have taken on excessive merchant generation or trading exposure in relation to their overall size, have seen their credit positions suffer most significantly. Companies that have taken significant exposure in many foreign markets – in particular those in Latin America – also have been negatively affected. On the other hand, companies whose investment programs have been well tailored to their available cash flow and balance sheet strength have been much less affected, as have those that have pre-emptively supported their growth plans through the issue of new equity or equity-linked securities. As a result, today there is a wide range of credit and balance sheet strength in the segment: some companies are eminently well positioned to meet the kinds of obligations required by FPL's RFP, while others are not. Given this wide range in financial conditions, it is especially important for FPL to carefully screen proposers for financial viability.

Q. Have there been significant changes in the IPP industry since FPL issued its last RFP in 2002 relative to the Martin 8 and Manatee 3 units?

A. Yes. During 2003 credit quality for the industry as a whole continued to deteriorate. During the year, there were 139 downgrades by S&P versus just eight upgrades, with some companies such as El Paso Corp., Duke Energy Corp., SEMCO Energy Inc., Aquila Inc., and Allegheny Energy Inc., experiencing multiple downward rating actions. Also, in the past year three companies have filed for bankruptcy protection. Significantly, as shown in the table below and described more fully in Exhibit No.___, Document No. MPD-1, credit ratings for twelve companies owning more than 200,000 MW of generation worldwide have fallen from generally investment grade to low non-investment grade levels. Five of these entities submitted proposals in FPL's last RFP solicitation.

Company	S & P Rating/Outlook as of January 2004	Company	S & P Rating/Outlook as of January 2004
AES	B+/Negative	El Paso	B/Negative
Allegheny	B/Negative	Mirant	D
Aquila	B/Negative	NEGT	D
Calpine	B/Negative	NRG	B+/Stable
Dynegy	B/Negative	Reliant	B/Negative
EME	B/Negative	Williams	B+/Negative

This deterioration has been the result primarily of highly leveraged investments, significant investments in international markets, and difficult market conditions in the U.S.

Liquidity has improved for the sector as a whole during 2003, as several of these companies successfully refinanced their bank facilities pushing out most of the $25 billion of debt maturing in 2003. Many of these companies have been selling selective assets (primarily power plants with associated long-term contracts and regulated pipelines) while others such as El Paso are exiting the electricity generation business completely. While cash from these sales and debt refinancings have kept some companies out of bankruptcy, debt leverage has actually increased, with $65 billion of debt maturing through the end of 2010.

Q. Were you surprised that FPL received 5 proposals from 4 IPPs in response to the RFP?

A. No. Given the financially distressed position of many of the members of the IPP industry, positions that, as I described above, have deteriorated further since FPL conducted its last solicitation in 2002, it is not surprising that FPL received 5 proposals. In fact, of the sixteen proposers who responded to FPL's Supplemental RFP in 2002, nearly all have had their ratings downgraded since May 2002. Specifically, nine now are rated below investment grade, with seven rated in the "B" category or lower by S&P and Moody's Investors Service (Moody's), with three of those in bankruptcy. Only five of the sixteen entities who submitted proposals in FPL's last solicitation in 2002 are rated as investment grade by the rating agencies. As discussed above, several companies are in the process of exiting the business, and others are actively selling assets to reduce debt levels. Consequently, I'm not surprised that fewer responses were received. Other factors discussed by Mr. Silva in his testimony also may have contributed to the number of proposal received.

Q. What concerns were presented for FPL in the RFP process as a result of the financially distressed state of many of the potential suppliers from the IPP industry?

A. Proposers' responses to the RFP represent promises of future commitments, which may or may not be met depending upon the specific circumstances of the particular proposer. Thus, it is necessary that FPL consider the reliability of each proposer's promises and its likely ability to meet its commitments. Factors such as a proposer's long-term financial viability, its operating track record, its stated or implied commitment to the business of operating generation projects, and its history of successfully delivering against commitments in prior projects are all important when making a long-term commitment to purchase power. A supplier that cannot complete construction of a plant according to the schedule agreed to, either because of operational failure or because of financial impairment, jeopardizes FPL's ability to provide power sufficient to meet customers' needs.

Similarly, a supplier must be able to maintain a strong financial profile over the life of the project. A supplier that fails to operate and maintain a project due to financial or other constraints will place FPL at risk of having to purchase replacement power on short notice and at the risk of higher prices or otherwise compromising system reliability. In addition, FPL may face increased risk of contract disputes with a financially weakened supplier. The cost of these various risks is ultimately borne by our customers, who will directly bear the costs of replacement power if the supplier does not have the financial wherewithal to correct operational problems or to pay the replacement power costs in the form of damages.

These concerns, although no different than FPL ordinarily would consider and did consider in its last RFP, obviously become increasingly important to the extent the financial condition of many prospective suppliers worsens. Consequently, FPL has taken steps in connection with its 2003 RFP commensurate with the generally weaker financial state of many entities within the IPP industry.

Q. Given the heightened concerns you have noted above, what minimum financial standards or requirements did FPL include in the RFP and the power purchase agreement?

A. The RFP and the power purchase agreement contemplate that the proposer possesses and maintains a minimum credit standard, and posts completion security if the proposal is for new construction. Additionally, the proposer is required to provide performance security for all proposals (new construction and existing facilities) throughout the operating period. These minimum standards are necessary to help ensure that the facilities which will provide contracted power will be constructed, completed on schedule, and operated and maintained in a manner consistent with the terms of the contract. Contract commitments alone are not sufficient to protect the customer. There must be sufficient amounts of cash on hand to pay for replacement capacity and energy, on short notice, in what could be tight supply conditions. In order for these contract provisions to have practical value and meaningful consequences, appropriate security amounts must be required of unregulated suppliers. Indeed, the ability and willingness of prospective suppliers to post the requisite security is a reasonable litmus test of their ability and willingness to follow through on their contractual commitments.

Q. Please describe FPL's use of debt rating agency ratings in assessing financial viability of potential proposers?

A. Credit assessments from the major credit rating agencies, S&P and Moody's, were used to set a minimum threshold of credit quality. While rating agency assessments have limitations and cannot be used as an absolute or sole indicator of financial viability for all purposes, I believe that for the purpose of providing a general indicator of a proposer's likely ability to meet its commitments under the RFP, they are a useful starting point. For example, it would be inappropriate to draw too fine a distinction between a company with an S&P rating of BBB+ and one with an A- rating. However, there is substantial evidence that default probabilities are correlated overall with ratings and, in particular, that default probabilities increase significantly as companies drop below the standard definitions of "investment grade."

Q. What is the minimum debt rating or financial viability standard required in the RFP?

A. FPL has specified as a Minimum Requirement that for proposals supported by newly built generation, the proposer or the guarantor of the proposer "'must possess a senior unsecured debt rating of not less than '"BBB-'" from S&P's

or "'Baa3'" from Moody's Investors Service with a "'stable outlook.'" S&P's definition of an investment grade issuer is an "...obligor who has adequate capacity to meet its financial commitments." A requirement that a proposer or guarantor of a proposer of newly built generation have, at a minimum, a BBB- S&P rating or a Baa3 Moody's rating helps ensure that the proposer will be able to obtain financing for the project and that cash flows will be available for ongoing maintenance of the project. The credit rating level chosen by FPL was the maximum level of risk to which FPL felt its customers should be exposed for an undertaking as significant as the financing and construction of a power plant. Based on Moody's annual study of default & recovery rates of corporate bond issuers, entities rated below investment grade have a historical five-year default rate of approximately 22 percent, substantially higher than the average default rate for higher rated entities. Such entities have low investment ratings because they reflect high risks to their investors and to counter-parties.

Q. **How does FPL know that a supplier who is credit worthy today will be so 6 months from now, or 10 years from now?**

A. Financial viability and credit quality are influenced by many factors, including market conditions, strategic decisions of management, and general economic conditions. Thus, there can be no guarantee that a company that is creditworthy today necessarily will be so in the future. However, while it is impossible to predict perfectly long-term viability, it is feasible to assess a proposer's current financial position and likely near-term (2 to 3 year) future financial position and to make informed judgements as to a supplier's ability to maintain a strong financial position. This may be accomplished using both publicly stated intentions and rating agency assessments. For FPL's purposes, the 2 to 3 year assessment is very important, because it coincides with the construction period for the assets that will be needed to fill the underlying capacity need. Because we applied a minimum credit threshold in our evaluation, it is not necessary to be absolutely precise about the relative levels of creditworthiness among proposers; rather, the intent was merely to ensure that entities that do not meet the minimum definition of creditworthiness were screened out. In addition to a minimum credit threshold, additional forms of security independent of credit ratings, such as completion security (for proposals with new construction) and performance security, can also be employed to protect our customers from the cost of supplier non-performance.

Q. Please describe the Completion Security requirement.

A. To help ensure timely completion of the project, the RFP and the power purchase agreement require that completion security be provided for any proposals for newly built generation in an amount equal to no less than $188,000 per MW of committed capacity. This security provides a ready source of funds to pay for replacement power if the project were to be delayed or to fail to achieve its in-service date and provides an incentive to the proposer to complete the project on schedule.

Q. How was the amount of Completion Security determined?

A. In formulating the completion security amount, FPL took a conservative approach, attempting to balance the need to protect customers with the financial impact of a security provision on a proposer. FPL captured in the completion security calculation the estimated incremental costs customers would face if FPL had to replace the energy and the capacity to be supplied by the proposer. It was assumed that FPL would purchase capacity necessary to meet its 20 percent reserve margin requirement for two years at $5/kW per month until FPL could bring four CTs into service. The calculation also assumed that FPL would continue to purchase capacity equal to the difference between its 1,066 MW need and the amount of capacity available from the four CTs until FPL could convert the four CTs into a 4x1 combined cycle unit. From this cost, FPL netted capacity costs it would not have to pay the proposers. It then added to this incremental cost its estimated replacement energy costs over the four-year period. In making that calculation, FPL made an assumption that the four CTs would not have to be removed from service to convert them from simple cycle to combined cycle mode. The total incremental cost was calculated and then divided by the total MWs of need to obtain a per MW value. Accordingly, the amount of the completion security required varies depending upon the MW of firm capacity proposed and, thus is a ratable requirement.

Q. Please describe the Performance Security requirement.

A. The RFP and the purchase power agreement also require that each proposer provide performance security in an amount equal to no less than $95,000 per MW of committed capacity. The performance security provision is included to protect customers from a developer failing to perform as it contracts. This failure to perform could manifest in a number of forms: failure to provide the contracted MW, failure to achieve the contracted heat rate, or failure to achieve contracted availability. In each instance the result is that FPL will incur replacement power costs that would be passed on to its customers. Should an event of default occur and not be cured, performance security helps provide funds necessary for FPL to purchase replacement power or to operate the plant and avoid passing the costs on to customers. The risk of less- than-contracted performance extends for the life of the PPA, which could be as much as 25 years. Rather than require proposers to post a security that would cover the potential damages for poor performance for the life of the contract, FPL determined that one half of the completion security, which envisioned essentially a four-year computation of damages as described below, would be a reasonable performance security balance.

Q. Is the entire amount of the Completion and Performance Security required in the form of cash or a Letter of Credit?

A. No. As described in the RFP and purchase power agreement (PPA), each entity will be assigned a Supplier Credit Limit based upon their unsecured debt rating and their tangible net worth as follows:

Unsecured Debt Rating	**% of Tangible Net Worth**
AAA+/Aaa1 to AA-/Aa3	20%
A+/A1 to A-/A3	15%
BBB+/Baa1 to BBB-/Baa3	10%
BB+/Ba1 and below or unrated	0%

Credit worthy entities with sufficient net worth can provide as little as ten percent of completion and performance security in a liquid form, i.e., cash or Letter of Credit (LOC). For example, a proposal for 1,000 MW would have to include a commitment to maintain completion security throughout the construction period in the amount of $188 million. If the Supplier were a "BBB" rated entity with two billion dollars of tangible net worth, the Supplier Credit Limit would be $200 million. Because the Supplier Credit Limit is greater than the completion security amount, the supplier would be required to post only ten percent of the completion security in the form of cash or a LOC. The remainder may be provided in the form of a corporate guarantee, at no out-of-pocket cost to the proposer.

Q. Please summarize the purpose of these minimum requirements and explain the role of step-in rights under the PPA.

A. The three functions of financial viability (minimum debt rating), completion and performance security provisions and step-in rights work in a balanced, non-redundant fashion to protect customers. The minimum financial viability and completion security requirements apply only to proposals involving the construction of a new facility. The financial viability requirement, or minimum debt rating, is necessary to minimize the risk of bankruptcy by a proposer, an event that carries its own set of costs and consequences for the purchasing utility and its customers which may only be partially, if at all, addressed by the other security requirements and step-in rights.

Once construction is completed, completion security is cancelled and replaced with performance security to provide protection to FPL's customers throughout the life of the contract. The completion and performance security provisions provide guarantees and cash equivalents to compensate our customers for their damages resulting from lack of completion and/or performance by the Developer. These requirements also provide meaningful incentives for the proposer to perform under the PPA as promised.

Where money damages alone are not sufficient to ensure that the lights will remain on, step-in rights give FPL the right to protect customers by performing work that the proposer is unable or unwilling to do.

In short, the provisions cited protect FPL's customers by 1) reducing the risk of the developer going bankrupt after FPL and its customers agree to rely upon the developer's commitment (financial viability); 2) making sure there are funds available to compensate them for extra costs caused by the proposer's failure to meet its promises (security provisions); and 3) providing FPL the option to complete and operate the plant in the event replacement power is not available (step-in rights).

Q. How did these standards and requirements affect the results of the economic evaluation?

A. In this instance, they were not determinative on the outcome of the evaluation. Although there were proposers who did not meet the minimum requirements, as Mr. Silva explains in his testimony, FPL elected to evaluate all proposals in the interest of moving forward with the process. At the same time FPL proceeded with its economic evaluation, FPL notified proposers of the nature and extent of any non-compliance and encouraged them to make changes to bring the proposals into compliance. However, as Mr. Silva describes, the evaluation indicated that no proposer failing to meet the minimum financial requirements had a competitive bid. Therefore, the failure of bids to comply with the minimum requirements was not a dispositive factor in the ultimate decision to proceed with Turkey Point Unit 5.

Q. What is an "equity adjustment" as employed by the Company in its analysis of responses to the RFP?

A. An equity adjustment is an adjustment made in the calculation of the total cost of supply options containing purchased power obligations to reflect the fact that such obligations draw upon the debt capacity of the Company and, other things being equal, must be offset by increasing the ratio of equity in the Company's financing mix. Mechanically, an equity adjustment is the net present value of the incremental cost of equity required to rebalance the Company's capital structure (the incremental cost of equity is measured relative to the cost of debt).

Q. Why is it appropriate for the Company to include an equity adjustment as a cost for the non-FPL proposals in the comparison of those bids to the FPL self-build options?

A. The equity adjustment is a real cost to a utility and its customers of entering into a purchase power agreement. In assessing a utility's credit quality, the bond rating agencies explicitly evaluate the utility's purchase power obligations. Based on that examination, the rating agencies attribute to the utility's balance sheet as debt-equivalent a portion of the net present value of the obligations under each power purchase agreement. The effect is to increase the relative share of debt and debt-like instruments in the capital structure. Accordingly, the utility needs to increase equity in its capital structure to attain the same level of financial security and flexibility with a purchased power obligation as without. The net present value of the incremental cost of increased equity to rebalance the capital structure must be added to the net present value of the cost of purchased power options evaluated to determine the total cost to FPL.

FPL's analysis of the bids took this incremental cost of capital into account. This comparison for each option enables FPL to fairly evaluate competing proposals against one another and against FPL self-build options. Were this not done, the economic comparison of self-build and external supply options would be biased in favor of the latter, leading to higher total revenue requirements to be borne by customers over the long run.

Q. Is the equity adjustment a one-sided adjustment as has been alleged in the past?

A. No. FPL's Equity Adjustment serves two essential purposes. First, it places RFP proposals on an equal footing with FPL's self-build options so that the net impact of both alternatives is to preserve an incremental 55 percent equity / 45 percent debt capital structure. Second, it captures the cost to FPL of restoring its capital structure to its target 55 percent equity / 45 percent debt ratio when FPL purchases power and rating agencies impute debt to FPL's capital structure. The impact of the FPL self-build option on FPL's capital structure is captured in using an incremental capital structure of 55 percent equity / 45 percent debt. The Equity Adjustment captures the corresponding impact on FPL's capital structure of purchased power agreements. Thus, it is not a one-sided adjustment.

It is undeniable that unless some offsetting action is taken, a utility's financial position will erode as a result of the imputed-debt effects from a purchase power contract. Thus, to assess properly the costs of expansion plans containing purchase power contracts, it is necessary to include the cost of additional equity required to rebalance FPL's capital structure to account for the imputed-debt impact of such contracts. In this way, the impact of purchased power on the utility's capital structure is held neutral relative to the capital structure assumed in assessing the costs of the self-build options. To do otherwise would ignore the undisputed impact of purchased power on a utility's balance sheet, resulting in a skewed comparison of the relative costs of the self-build and purchased power options by failing to hold the utility's capital structure neutral.

Indeed, it is the <u>failure</u> to include an equity adjustment in the evaluation that would provide a one-sided perspective: one which would be tantamount to a subsidy of purchased power. The cost to rebalance FPL's capital structure is a cost of both FPL's proposed unit and any purchase power option under consideration. It must be considered for both to make an appropriate determination of the lowest cost option for FPL's customers.

Q. Please describe the basic methodology employed to determine the amount of imputed debt.

A. While all of the rating agencies take off-balance sheet obligations into account when evaluating credit quality, S&P uses an approach that has both quantitative and qualitative aspects to value the debt component of off-balance sheet obligations. It involves first computing the net present value of the remaining capacity payments under the contract. A risk factor is then determined based primarily on the method of recovery of capacity payments. Once the risk factor is determined, it is then multiplied by the net present value of the remaining capacity payments to determine the amount of off-balance sheet obligation to include as debt in the capital structure of the company for purposes of analyzing credit quality.

Q. Have there been any new developments in the way rating agencies determine the amount of imputed debt since FPL conducted its last RFP?

A. Yes. In its last RFP, FPL employed a risk factor of 40 percent. S&P had indicated that it likely would assign the purchased power agreement a risk factor ranging from 40 to 60 percent, i.e., it would add to the Company's balance sheet between 40 and 60 percent of the net present value of the capacity payments as debt-equivalent. To be conservative and to avoid debate over which portion of this range more fairly represents the appropriate risk factor, FPL elected to use the bottom of the range, i.e., 40 percent, for purposes of its analysis.

Since FPL issued its last RFP in which it employed a risk factor of 40 percent, S&P has revised its methodology for determining the size of the risk factor. S&P previously established the risk factor based primarily on the relative likelihood that the purchaser would be required to make payments under the purchased power agreement. Under its revised approach, S&P now assigns the risk factor based predominantly on the method of recovery of purchased power costs, along with an assessment of other economic and regulatory factors. S&P now assigns utilities with PPAs included as an operating expense in base tariffs a 50 percent risk factor. However, "[f]or utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of *as low as 30% could be used.*" RFP, Appendix 2, Standard & Poor's Utilities and Perspectives, May 12, 2003, at 2-3 (emphasis added). FPL elected to use 30 percent, the lowest possible factor specified by S&P for utilities in supportive jurisdictions like Florida that have a purchase power cost recovery clause.

Q. How did the Company calculate the incremental cost of equity or "equity adjustment" for each bid in this case?

A. We estimated the amount of imputed debt based on the S&P methodology described above, using a risk factor of 30 percent. Once the imputed debt is calculated, equity would be required to rebalance the Company's capital structure (currently approximately 55 percent equity on an adjusted basis) in order to maintain comparable financial flexibility and credit quality. The equity adjustment represents the net present value of the incremental cost of the equity added to the capital structure.

The equity adjustment is then added to the net present value of the capacity payments under each contract to determine the total cost of each option. Once this is done, a meaningful comparison of the total cost of each option with FPL's self-build option can be made. The equity adjustment computations are shown in Appendix C-5 to the Need Study.

Q. Does this 30 percent risk factor consider the impact of a potential supplier's financial viability, as discussed earlier in your testimony?

A. No. The risk factor assigned by S&P represents the rating agency's assessment of the debt characteristics of a particular purchased power agreement. While this entails an examination of a variety of qualitative factors related to the underlying agreement and the extent to which the related financial risks are borne by FPL and its customers, S&P's assessment implicitly presumes that the generating facility has been placed in service and is operating under the terms of the purchased power agreement contemplated in the RFP. Thus, the risk factor does not directly address the financial viability of individual suppliers or the impact that this has on the ability of a particular proposer to meet its commitments.

Q. Has the Commission previously recognized that the use of an equity adjustment in assessing the true costs of purchased power alternatives is appropriate?

A. Yes. In Order No. PSC-01-0029-FOF-EI, the Commission found Florida Power Corporation's consideration of imputed debt based on a risk factor of 40 percent to be appropriate for purposes of comparing third party proposals to FPC's self-build option, the Hines Unit 2. The Commission also allowed consideration of imputed debt in approving FPL's Standard Offer Contract in Order No. PSC-99-1713-TRF-EG. Most recently, at its February 17, 2004 Agenda Conference, the Commission approved Staff's recommendation in Docket No. 031093-EQ to allow the inclusion of an equity adjustment in FPL's Standard Offer Contract.

Although the Commission declined to recognize the use of an equity adjustment in FPL's last need case, the Commission rejected the contention that an equity adjustment was improper. Instead, in Order No. PSC-02-1743-FOF-EI at page 20, the Commission said that "consideration of an equity adjustment is appropriate." According to the Commission in that order, "in future dockets, a case-by-case examination of the entire circumstances surrounding the evaluation of PPAs … and the presence or absence of any mitigating factors shall be considered." Most recently, the Commission's staff has recommended approval of an equity adjustment in FPL's standard offer contract based on a 30 percent risk factor. Docket No. 031093-EQ.

For the reasons I have stated above, I believe the equity adjustment proposed by FPL in connection with its evaluation of purchased power options is necessary and appropriate.

Q. Did FPL consider the presence or absence of mitigating factors in conducting its evaluation?

A. Yes. While the S&P methodology takes a broad look at the debt equivalence of purchased power obligations, there may be other factors that may be considered as mitigating the effect of such purchased power obligations. FPL considered the mitigating effects of purchased power relative to its impact on the Company's balance sheet. As described in the RFP, Appendix C, pages 3 - 8, such mitigation stems principally from the benefits offered by the completion and performance security required in connection with a purchased power agreement.

Q. What are the mitigating effects offered by the Completion and Performance Security?

A. Completion and performance security address the risk of delivering less capacity than that which has been proposed and/or under performance relative to the agreement. With an FPL self-build option, there is some small probability that such an event might occur, and that impact would not be mitigated by FPL's contractual arrangements. If this occurred and it was determined by the FPSC that FPL was not imprudent, any incremental cost caused by such a delivery shortage or under performance might be recovered from FPL's customers. Therefore, the completion and performance security could mitigate the impact of those costs on FPL's customers.

The value that FPL assigned to the mitigation provided by a PPA is based upon estimates of the probabilities of a FPL delivery shortage and/or under performance, multiplied by the amount of completion and performance security.

Q. How were these mitigating factors applied in the evaluation process?

A. These factors were added as a credit to (reducing the magnitude of) the equity adjustment to obtain the mitigated equity adjustment. The direct testimony of Steve Sim describes how the mitigating factors were computed and included in the equity adjustment applied to each proposal.

Q. Were proposers notified in advance that FPL would apply an equity adjustment and would consider mitigating factors?

A. Yes. FPL's RFP provides an extensive explanation of the equity adjustment, its computation and use in the evaluation, and how mitigating factors would be applied in the methodology. This was included in Section IV.D, p. 29, and Appendix C of the RFP.

Q. Does this conclude your testimony?

A. Yes, at this time.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF WILLIAM E. AVERA

DOCKET NO. 04_____-EI

March 8, 2004

I. INTRODUCTION

Q. Please state your name and business address.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

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

A. I am a principal in Financial Concepts and Applications, Inc. (FINCAP), a firm engaged in financial, economic, and policy consulting to business and government.

Q. Describe your educational background, professional qualifications, and prior experience.

A. I received a B.A. degree with a major in economics from Emory University. After serving in the United States Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas (PUCT) as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission (FERC), the Federal Communications Commission (FCC), the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in 30 states, including the Florida Public Service Commission (the Commission or FPSC).

I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas Legislature on the costs and benefits of connecting Texas to the national electric transmission grid. Currently, I serve as an outside director of the Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I also have served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners (NARUC) Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I also have served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached as Document WEA-1.

Q. What is the purpose of your testimony?

A. As a result of its resource planning process, Florida Power & Light Company (FPL or the Company) has identified the need for additional firm capacity in the amount of approximately 1,066 megawatts (MW) in 2007 to meet its targeted reserve margin. FPL selected from among a number of self-build options a capacity addition at its Turkey Point plant as its next planned generating unit (NPGU) to meet that need. FPL subsequently issued its 2003 Request for Proposals (RFP) to solicit competitive power supply alternatives to compare to its NPGU and identify the option for new resources that best serves the needs of FPL's customers. In connection with the final economic evaluation of individual proposals, the RFP provides for an equity adjustment to recognize the impact of purchased power contracts on FPL's financial position for obligations of more than three years.

The purpose of my testimony is to explain the impact that power purchase contracts have on FPL's financial leverage and present to the FPSC the method FPL is proposing to account for these impacts in the economic evaluation of capacity alternatives under the RFP.

Q. Are you sponsoring an exhibit in this case?

A. Yes. It consists of Document No. WEA-1, Resume of William E. Avera.

Q. Please summarize the basis for your conclusions concerning the issues on which you are testifying in this hearing.

A. As is common and generally accepted in my field of expertise, I have accessed and used information from a variety of sources. I am familiar with the organization, finances, and operations of FPL through my participation in prior proceedings before the FPSC, including the Martin/Manatee need case (Docket No. 020262-EI) and the FPSC's last review of FPL's rates (Docket No. 001148-EI). I also reviewed information relating specifically to my opinions in this proceeding, including bond rating agency reports, prior regulatory proceedings and orders, and articles in the trade press. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of FPL and are the basis for my conclusions.

Q. What are your conclusions regarding the impact of purchased power contracts on FPL's financial position?

A. Investors regard purchased power contracts as off-balance-sheet obligations that increase the financial leverage of the purchaser. To maintain bond ratings and financial flexibility, utilities must offset the debt equivalent of purchased power obligations by increasing the equity component of the capital structure from what it would otherwise be. The impact of imputed debt from purchased power obligations has been recognized in past orders of the Commission and bond rating agency reports. Considering the cost of additional equity that is required to offset the debt equivalent of purchased power commitments is consistent with FPSC orders and the treatment afforded these obligations by the major rating agencies. FPL's equity adjustment calculation, which considers both the costs of the debt equivalent imposed by purchased power contracts and the potential offset provided by other mitigating factors, reasonably accomplishes this adjustment.

II. BACKGROUND

Q. How do these long-term purchased power commitments impact FPL's financial leverage?

A. While purchased power resource strategies do not involve direct capital investment, they nonetheless have financial implications that must be considered to allow for a meaningful comparison between supply alternatives. When a utility enters a contract for firm, long-term purchased power, the associated fixed cost components imply additional financial risks because the fixed charges associated with purchased power contracts are akin to those associated with other financial obligations, such as long-term debt. FPL's existing power purchase agreements, along with any proposals submitted in response to its RFP, obligate the Company to make certain capacity and minimum contractual payments. As a result, these commitments are equivalent to an off-balance sheet liability, and incorporating the debt equivalent of obligations under purchased power contracts would have the effect of increasing financial leverage.

Q. Have these attributes of purchased power been recognized by the financial community?

A. Yes. The implications of purchased power commitments for a utility's financial risks have been repeatedly cited by major bond rating agencies. As early as 1990, Moody's Investors Service (Moody's) recognized the financial risk imposed by the off-balance-sheet liabilities associated with purchased power and the resulting erosion of the utility's financial flexibility (*Electric Utility Week*, October 8, 1990). Similarly, Standard & Poor's Corporation (S&P) observed in a 1992 ratings report for FPL that "a utility incurs certain risks when entering into a long-term contract with fixed-cost capacity component" (*CreditWeek*, April 6, 1992). As S&P observed in "Buy Versus Build Debate Revisited" (*CreditWeek*, May 24, 1993):

> When a utility enters into a long-term purchased power contract with a fixed-cost component, it takes on financial risk. Heavy fixed charges reduce a utility's financial flexibility and long-term contractual arrangements represent – at least in part – off balance sheet debt equivalents. (pp. 1-2)

More recently, in reviewing its evaluation of the credit implications of purchased power, S&P reaffirmed its position that such agreements are "debt-like in nature" and that the increased financial risk must be considered in evaluating a utility's credit risks ("'Buy Versus Build': Debt Aspects of Purchased-Power Agreements", *Utilities & Perspectives*, May 12, 2003).

Because the capacity and minimum contractual payment obligations under power purchase agreements are analogous to those associated with traditional debt financing, investors consider these commitments in evaluating FPL's financial risks. Accordingly, incorporating the debt equivalent of FPL's obligations under its purchased power contracts in the Company's capital structure would have the effect of increasing its financial leverage.

Q. What implications do relatively greater amounts of purchased power have for a utility's financial flexibility?

A. Because investors perceive additional financial risks with obligations under purchased power contracts, as reliance on these sources increases, the utility must offset the associated debt equivalent by incorporating a higher equity component in the capital structure to neutralize the effect on leverage. As S&P has recognized, because of purchased power, it has been necessary for FPL to maintain a relatively greater proportion of equity capital in order to maintain its credit standing. In a December 3, 1998 report in *RatingsDirect*, S&P noted that:

> Florida Power & Light has a sizeable amount of fixed payment purchased-power contracts, a portion of which is imputed by Standard & Poor's as an off-balance-sheet obligation, and has maintained a higher amount of equity capital on the balance sheet to counter this off-balance-sheet debt obligation. (p. 2)

More recently, S&P noted that it "includes about $1.3 billion as a debt equivalent" because of FPL's purchased power obligations (*Research: FPL Group, Inc.*, Oct. 21, 2003). Absent financial policies that recognize the leverage implicit in purchased power contracts, the associated investment risks would place downward pressure on utilities' creditworthiness and debt ratings and the greater leverage implied by a lower common equity ratio would increase investors' required rate of return for both debt and equity securities.

Apart from the immediate impact the debt-equivalent portion of purchased power costs has on the utility's financial risk, heavy fixed charges also reduce ongoing financial flexibility, and the utility may face other uncertainties, such as potential replacement power costs in the event of supply disruption. Moreover, investors' focus on the financial ramifications and other uncertainties of purchased power is magnified as the utility's reliance on purchased power increases. The 1,066 MW increase in purchased power contemplated under FPL's RFP would constitute a greater than 40 percent increase in the Company's firm purchased power capacity, which totaled approximately 2,400 MW for 2002 (*2003 Request for Proposals (RFP)*, Attachment 1).

Q. Is it appropriate to consider these financial implications in an economic evaluation of power supply alternatives?

A. Yes. To conduct a meaningful economic comparison between buying power and self-build options, it is necessary to recognize the financial risks associated with power purchase contracts. Otherwise, the analyses will not reflect the true cost of entering into purchased power agreements and any comparison of the economics between alternative proposals will be flawed. S&P noted that "(u)tilities need to take these 'financial externalities' into account so that buy and build options are evaluated on a level playing field" (*CreditWeek*, May 24, 1993) and emphasized the importance of reflecting the financial realities associated with purchased power commitments in any economic analyses of competitive options (*CreditWeek*, November 1991). S&P recently confirmed that an evaluation of the financial risks associated with purchased power commitments is necessary "to allow for more meaningful comparisons with utilities that build generation" (*Utilities & Perspectives*, May 12, 2003).

Q. What other indications confirm the need to properly consider the financial impacts of purchased power commitments?

A. Investors are aware of the impact that purchased power can have on a utility's investment risks. As S&P observed in 1993 (*CreditWeek*, May 24, 1993), the financial impact of purchased power directly influences credit standing and financial flexibility:

> Over the past few years, several ratings have been lowered due to purchased power obligations. In other cases, S&P did not raise ratings. Still others are lower than they might otherwise be owing to purchased power liabilities.

In the wake of recent turmoil in the electric power industry, bond rating agencies and investors are continuing to scrutinize debt levels. For those firms with higher leverage, this intense focus can lead not only to ratings downgrades, but also to reduced access to capital and increased borrowing costs. The Wall Street Journal reported ("Rating Agencies Crack Down on Utilities", p. C1, December 19, 2001) that even firms with stock prices at recent lows may be forced to issue new common equity in adverse markets and quoted a credit analyst with Fitch, Inc.:

> "(B)anks are fearful to put more money into the sector" and it is making credit analysts nervous as well. The smart

companies, he says, are the ones that voluntarily "get their balance sheets in line" and then "let the market know they're in charge of their destiny ... since the market clearly has the heebie-jeebies."

The article went on to note the crucial role that financial flexibility plays in ensuring that the utility has the wherewithal to meet the needs of customers, especially during times of stress:

All the belt tightening spells bad news for the continued development of the nation's energy infrastructure. Companies that can borrow more money and stretch their dollars, quite simply, can build more plants and equipment. Companies that are increasingly dependent on equity financing – particularly in a bear market – can do less.

Q. Has the FPSC previously recognized the impact that purchased power contracts have on the utility's finances?

A. Yes. Rule 25-22.081(7), F.A.C., relating to the contents of a petition for determination of need, specifically requires utilities to address the cost impact of purchases on their capital structure:

If the generation addition is the result of a purchased power agreement between an investor-owned utility and a nonutility generator, the petition shall include a discussion of the potential for increases or decreases in the utility's cost of capital, the effect of the seller's financing arrangements on the utility's system reliability, any competitive advantage the financing arrangements may give the seller and the seller's fuel supply adequacy.

In past decisions, the FPSC has acknowledged that an equity adjustment is appropriate to address the capital structure impact associated with purchase alternatives. For example, in connection with Florida Power Corporation's petition for approval to construct the Hines Unit 2 power plant, the FPSC recognized an adjustment for the debt equivalent of purchased power options, noting in Order No. PSC-01-0029-FOF-EI (January 5, 2001) that:

> We find that for long-term debt, we should allow some consideration of imputed debt. Imputed debt is an actual consideration by bond rating agencies. We note that we have allowed limited consideration of imputed debt in past cases.

Similarly, in Docket No. 990249-EG, Standard Offer Contract for Florida Power & Light Company, the FPSC concluded that "(w)e find it is appropriate to include an equity adjustment when determining FPL's proposed standard offer contract payments" (*Order No. PSC-99-1713-TRF-EG*, September 2, 1999). While the Commission chose not to address the broader policy issue of who should bear the incremental cost of additional equity to compensate for purchased power contracts, the FPSC recognized (*Ibid.* at p. 7-8) that:

> Buying power increases the utility's fixed charges, which, in turn, can reduce financial flexibility. Standard & Poor's (S&P) notes that, "regardless of whether a utility buys or builds, adding capacity means incurring risk." ... In including this equity adjustment, FPL is reflecting the cost, in the form of less financial flexibility, that is imposed on electric utilities with purchased power contracts.

Moreover, the FPSC continues to recognize the financial leverage implicit in purchased power contracts in the approach used for surveillance reporting requirements. The current Revenue Sharing Agreement in effect for FPL included in Order No. PSC-02-0501-AS-EI, April 11, 2002, incorporates by reference the following provision from the Stipulation and Settlement approved by the Commission in 1999 (*Order No. PSC-99-0519-AS-EI*, March 17, 1999):

> (FPL's) adjusted equity ratio equals common equity divided by the sum of common equity, preferred equity, debt and off-balance sheet obligations. The amount used for off-balance

sheet obligations will be calculated per the Standard & Poor's methodology as used in its August 1998 credit report.

Similarly, in a recent memorandum regarding FPL's proposed standard offer contract (*Memorandum*, Docket No. 031093-EQ, Feb. 5, 2004), the FPSC's Division of Economic Regulation concluded that "staff believes it is appropriate for FPL to make an equity adjustment as proposed in the determination of capacity payments in its Standard Offer Contract." Staff affirmed FPL's calculations based on S&P's current methodology, with the FPSC subsequently confirming at its February 17, 2004 Agenda Conference that it would be appropriate for the Company to make an equity adjustment.

Q. Does the Commission's decision in the Martin/Manatee need case (Docket No. 020262-EI) also support consideration of the equity adjustment in this case?

A. Yes. While the FPSC declined to recognize the application of an equity adjustment in evaluating alternatives to self-build options in FPL's last need case, the Commission expressly confirmed that "consideration of an equity adjustment is appropriate" (*Order No. PSC-02-1743-FOF-EI*).

Q. What is your understanding of why the Commission declined to adopt FPL's proposed equity adjustment in the Martin/Manatee proceeding?

A. The Commission determined there was not sufficient evidence concerning the potential impact of other factors associated with purchased power that might serve to mitigate a portion of the additional financial costs imposed by the debt equivalent of long-term supply contracts. Thus, while the FPSC expressed "particular concern" regarding the need to examine the presence *or absence* of mitigating factors, the Commission recommended that a case-by-case examination of the entire circumstances surrounding the equity adjustment be considered in subsequent proceedings (*Id.*).

Q. Does FPL's proposed equity adjustment specifically account for other factors that might mitigate the financial costs associated with entering into purchased power contracts?

A. Yes. The equity adjustment mechanism proposed by FPL (RFP, Appendix C) specifically captures the impact of mitigating factors in two ways. First, "the presence or amount of other factors which financial rating agencies may take into account in mitigation of the equity adjustment" (*Order No. PSC-02-1743-FOF-EI*) are already incorporated into S&P's methodology. As explained in greater detail subsequently, calculation of the debt equivalent associated with purchase power obligations depends in part on an assigned "risk factor", which reflects the rating agency's overall assessment of the risks that a utility assumes when purchasing power under contract. While the most significant attribute in establishing this risk factor is the risk of recovering the costs of purchased power, S&P's review encompasses "a qualitative analysis of market, operating, and regulatory risks" (CreditWeek, May 24, 1993). S&P

noted that its current assessment "takes several variables into consideration, including the economics of the power and regulatory treatment" (*Utilities & Perspectives*, May 12, 2003). Examples of these qualitative economic and regulatory factors were identified in S&P's 1993 publication and are displayed in the following table:

Category	**Risk Factor**
Market	Need for Power
	Economics
Operating	Performance Standards
	Reliability
	Dispatchability
	Control Over Maintenance
	Flexibility and Diversity
Regulatory	Preauthorized
	Regulatory Recovery Mechanism
	Regulatory Out Clause

Thus, in establishing its overall risk factor, S&P has already considered a host of "qualitative risk mitigators" (*CreditWeek*, May 24, 1993) that serve to offset the financial costs of purchased power contracts and these offsetting factors are incorporated into FPL's equity adjustment.

Second, FPL's application of the equity adjustment specifically includes provisions to quantify the potential offsetting impact of two mitigating factors – completion security and performance security. As detailed in Appendix C to the RFP, FPL's equity adjustment incorporates offsetting credits to the financial costs of purchased power contracts. These credits are designed to account for quantifiable differences between the delivery and performance risks of purchased power versus self-build options. Thus, in addition to the mitigation already built into the risk factor used to quantify the equity adjustment, FPL has included specific, quantitative adjustments to capture two broad categories of potential mitigation.

Q. Does the equity adjustment somehow depend on the assumption that entering into a purchased power agreement would lead to a change in bond ratings?

A. No. A utility's credit ratings are established based on a plethora of qualitative and quantitative factors. While investors clearly recognize that the debt equivalent of purchased power obligations has a quantifiable impact on financial risks and reduces a utility's financial flexibility, the incremental investment risk may not rise to the level necessary to prompt a revision to the utility's bond ratings. Indeed, because FPL's financial policies have explicitly recognized the leverage implicit in purchased power contracts, it would come as no surprise that some increment of additional purchased power could be accommodated without immediate negative actions on the part of bond rating agencies.

Regardless of whether additional purchased power triggers a change in bond ratings, every additional obligation increases the Company's leverage. Recognizing the equity adjustment is necessary, not to measure the potential change in bond ratings, but simply to account for quantifiable cost differences between power supply alternatives. The incremental costs that are associated with additional financial leverage arising from purchased power contracts are one such difference that has been recognized by the investment community and the FPSC.

III. EQUITY ADJUSTMENT

Q. Please describe the methodology used by S&P to reflect the financial impact of purchased power obligations.

A. While other rating agencies have expressed similar concerns regarding the financial impacts of purchased power commitments, S&P is largely unique in having a defined quantitative analysis to account for the additional risks associated with these contractual commitments. This methodology begins by quantifying the potential off-balance sheet obligation attributable to long-term power purchase contracts. The first step in this process involves calculating the net present value of the remaining capacity payments over the life of the agreement, determined using a discount rate of 10 percent.

Next, S&P evaluates the characteristics of a utility's purchased power contracts, placing each agreement on a risk spectrum according to the degree to which payments under the contract resemble the fixed obligations of traditional debt instruments, such as long-term bonds. Within the S&P analytical framework, this difference in the relative debt characteristics of purchased power obligations is accommodated using a risk spectrum ranging from 0 to 100 percent. This risk factor represents the proportion of the obligations' net present value to be considered off-balance sheet debt. For example, if S&P determines that the risk factor for a specific purchased power contract is 50 percent, S&P considers 50 percent of the net present value of the related capacity payments as a debt equivalent and adds this to reported obligations.

As noted earlier, in determining the risk factor S&P considers a variety of qualitative factors related to the purchased power contract. Previously, contracts that were relatively more firm in terms of their delivery and payment obligations were generally considered more debt-like than others. However, in a May 12, 2003, report ("'Buy Versus Build': Debt Aspects of Purchased-Power Agreements," *Utilities & Perspectives*), S&P explained that it had revised its approach to recognize significant structural changes in the electric power industry. Rather than evaluating the likelihood of payment under purchased power contracts, S&P has revised its assessment to place particular emphasis on the method under which the utility recovers of purchased power costs. For example, assuming adequate regulatory treatment, S&P now assigns a 50 percent risk factor where payments under long-term purchased power commitments are included in a utility's base rates. S&P concluded (*Utilities & Perspectives*, May 12, 2003) that a risk factor as low as 30 percent could be justified for utilities with supportive regulation that recover purchased power costs via a fuel adjustment clause (FAC), as opposed to base rates:

For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased power costs, a risk factor of as low as 30% could be used.

Q. Please describe the method FPL has proposed to reflect the greater financial leverage associated with purchased power in its economic evaluation under the RFP.

A. Consistent with the fact that investors view some portion of a utility's capacity payment obligations as the equivalent of debt on the balance sheet, FPL's quantitative analyses reflect an equity adjustment to incorporate the additional costs associated with the greater equity that would be required to rebalance its capital structure.

For each year under the proposal, the cumulative net present value of the remaining annual demand charges was calculated using the same 10 percent discount rate utilized by S&P. To arrive at the debt equivalent portion of these demand charges in each year, this cumulative net present value is multiplied by a risk factor of 30 percent. This corresponds to the lowest factor specified by S&P for an integrated utility that recovers purchased power costs through a FAC and is identical to the risk factor applied to FPL by S&P in its own analysis (*Research: FPL Group, Inc.*, Oct. 21, 2003). To offset the greater financial leverage associated with this obligation, FPL must replace a portion of this off-balance-sheet debt with equity, calculated as the product of the debt equivalent and a 55 percent equity ratio. The incremental cost associated with this rebalancing is then computed by multiplying the amount of capital implicitly shifted from debt to equity by the difference between the pre-tax cost of the two capital sources. Thus, the equity adjustment represents the incremental costs in each year that would be required to hold FPL's financial leverage constant in the face of the higher off-balance-sheet liabilities attributable to the purchased power proposals. These annual costs are then converted to a present value using the weighted average after-tax cost of debt and equity capital. A detailed illustration of the method described above is contained in Appendix C to the RFP.

Finally, as indicated earlier, FPL's equity adjustment also includes specific provisions to offset the costs required to rebalance the Company's capital structure by mitigation offered through the completion and performance security. These factors, which are designed to accommodate measurable differences in delivery and performance risk between purchased power and self-build options, are in addition to qualitative factors considered by S&P in its evaluation of the risk factor used to determine the debt equivalent of purchased power obligations.

Q. Is the methodology underlying the equity adjustment proposed by FPL consistent with the S&P approach adopted in prior FPSC proceedings?

A. Yes. The equity adjustment calculation employed by FPL is directly analogous to the methodology used by S&P in its analyses of FPL's credit standing. S&P's focus remains primarily on balance sheet adjustments designed to recognize the credit implications of heightened financial risks associated with purchased power, while FPL's adjustment quantifies the implicit costs of rebalancing between debt and equity to offset these risks. The methodology used by FPL to measure the off-balance-sheet obligation associated with purchase power obligations is identical to S&P's approach. Further, but for the additional consideration of specific mitigating factors, FPL's proposed equity adjustment methodology is the same as that approved by the FPSC in Order Nos. PSC-01-0029-FOF-EI and PSC-99-1713-TRF-EG discussed earlier.

Q. What capital structure and component costs of debt and equity are incorporated in FPL's proposed calculation of the equity adjustment?

A. FPL's equity adjustment is developed based on the assumption that the capital structure is rebalanced to maintain a 55 percent equity ratio after reflecting the impact of imputed debt from off-balance sheet obligations (adjusted equity ratio). In computing the associated costs implicit in this rebalancing, the equity adjustment assumes a rate of return on common equity of 11.0 percent and an incremental debt cost of 6.4 percent.

Q. Do you believe these assumptions are reasonable for purposes of an economic evaluation of purchased power alternatives?

A. Yes. The 55 percent adjusted common equity ratio incorporated in calculating the equity adjustment is consistent with FPL's current and historical adjusted capital structure. Further, the current Revenue Sharing Agreement arising from the stipulation in Docket No. 001148-EI retained the adjusted capital structure for surveillance reporting requirements specified under the terms of the prior agreement that expired in April 2002. This prior agreement also embodied a 55.83 percent surveillance cap on the adjusted common equity ratio.

With respect to the component costs of debt and equity, a 6.4 percent incremental cost of debt is generally consistent with the current yields on public utility bonds. Meanwhile, under the terms of the current Revenue Sharing Agreement, FPL no longer has a benchmark authorized return on equity range for the purpose of addressing earnings levels. Nevertheless, the 11.0 percent cost of equity is the return specified in the order approving the current Revenue Sharing Agreement "to be used for all other purposes" (*Order No. PSC-02-0501-AS-EI*).

Q. Does FPL's evaluation properly account for the impact of its self-build options on the Company's finances?

A. Yes. The cost of financing FPL's self-build options is incorporated into the

Company's evaluation through the capital structure and component costs of financing, just as FPL has proposed to evaluate purchased power alternatives. FPL assumes the same capital structure of 55 percent equity / 45 percent long-term debt – and the same component costs of debt and equity – in evaluating its self-build options. Because FPL uses identical assumptions to capture the financing impact of its self-build options, the Company's evaluation is neutral between self-build and purchased power alternatives.

Q. Does the equity adjustment incorporate any provision to reflect the relative credit quality of the individual counterparties?

A. No. The terms of FPL's RFP explicitly contemplate that counterparties will maintain an investment grade bond rating or an equivalent guarantee for new construction proposals. In addition, the relative strength of the proposer is considered in determining the type of credit support to be provided (*i.e.*, cash, letter of credit, or guarantee). Accordingly, in conducting the analyses used to quantify the equity adjustment, no modifications were made to incorporate project sponsor risk differences. Nonetheless, the financial wherewithal of the counterparty may impact the risks faced by FPL, especially in extreme instances. As S&P observed (*CreditWeek*, November 1991):

> (H)ighly leveraged NUGs [non-utility generators] are inherently less creditworthy than less leveraged NUGs. And their financial health may affect their reliability.

The risk spectrum used to calculate the equity adjustment reflects the relative debt characteristics of the off-balance sheet liability associated with a purchased power contract. As such, it is distinct from any assessment of the financial viability of a specific counterparty or that entity's ability to actually meet the provisions of the agreement.

Q. **Does this conclude your direct testimony in this case?**

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF C. MARTIN MENNES

DOCKET NO. 04 _____-EI

March 8, 2004

Q. Please state your name and business address.

A. My name is C. Martin Mennes. My business address is 9250 West Flagler Street, Miami, FL 33174.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL") as Vice President of Transmission and Substation.

Q. Please describe your duties and responsibilities as Vice President of Transmission and Substation.

A. I am responsible for FPL's bulk and regional transmission planning, operations, engineering and construction. This includes responsibility for the reliability and security of the FPL transmission system, which includes approximately 6,379 circuit miles of transmission lines.

Q. Please describe your educational background, business experience, and professional associations.

A. I graduated with honors from the University of Florida in 1968 with a Bachelor of Science degree in Electrical Engineering. I earned a Post-Graduate Certificate of Proficiency in Electrical Engineering from the University of Miami in 1974, and completed the Program for Management Development from the Harvard University Graduate School of Business in 1981. I am a registered Professional Engineer in the State of Florida.

I began working at FPL in 1968 in the area of protective relay and control systems. Since then I have held the positions of Manager of System Protection, Manager of System Operations, Manager of Bulk Power Markets, Director of Power Supply, Vice President, Transmission Operations and Planning, and Vice President, Transmission and Substation. On July 1, 2003, I assumed my present position.

My industry-related activities include serving as the chair of the following organizations: North American Electric Reliability Council ("NERC") Performance Subcommittee, NERC Security Coordinator Subcommittee, Southeastern Electric Reliability Council ("SERC") Operating Committee ("OC"). I have represented the transmission owners by serving as vice chair of the Industry Commercial Practices Working Group and the NERC Market Interface Committee. Presently, I am the Investor Owned Utility representative to the NERC-OC and chair of the Florida Reliability Coordinating Council ("FRCC")-OC. I also have worked on numerous NERC committees and taskforces including the Transmission Transfer Capability Taskforce and the Electronic Information Network Taskforce.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to provide an overview of the FPL electric system. I will also discuss FPL's continuing concern with the growing imbalance between load and generation in the Southeast Florida area and its impact on costs. In addition, I will describe the transmission-related costs assessment that was performed as part of this Request for Proposals ("RFP").

Q. **Are you sponsoring any part of the Need Study for this proceeding?**

A. Yes, I co-sponsor Section V.B. and sponsor Appendix A of the Need Study.

Q. **Please describe FPL's transmission system.**

A. The FPL transmission system is comprised of 6,379 circuit miles of transmission lines. The FPL transmission system is designed to integrate in a reliable and cost effective manner all of FPL's generation resources to serve FPL's retail customers and to meet FPL's firm long-term transmission service obligations. It is designed consistent with NERC and FRCC reliability criteria.

Q. FPL has stated there is a load / generation imbalance in the southeast area of its service territory. Please explain that imbalance.

A. The southeast area of FPL's system is the region south and east of and including FPL's Corbett Substation; this includes a portion of southern Palm Beach County and Broward and Miami-Dade counties. By 2007 FPL will have about 12,000 MW of load in this area, and the load is forecasted to continue to grow by about 250 MW per year. Currently, FPL has only 6,459 MW of installed capacity in the Southeast Florida area, and there are no planned generation additions in this area before 2007. As the load in Southeast Florida continues to grow, FPL will need to rely upon its transmission system to import greater amounts of power into the area to serve the load. However, FPL has a finite capability of about 7,000 MW to import power into Southeast Florida. This import capability is lower when multiple generating facilities or transmission facilities in Southeast Florida are unavailable due to maintenance or forced outages. This is the load / generation imbalance issue which FPL has identified.

Q. What impact does the Southeast Florida imbalance have on transmission costs to FPL's customers related to the addition of generation resources?

A. Transmission integration costs tend to be higher for generation additions located outside of Southeast Florida. Also, locating new generation units outside of Southeast Florida increases the amount of power moved over longer distances. Depending on the specifics of the transmission facilities required for integration, increased transmission losses could result. Higher transmission losses increase costs because the capacity and energy that is lost must be replaced. In addition, the location of new generation resources outside of Southeast Florida could, depending on the impact the transmission facilities required for integration have on the capability to import power into this area, affect the extent to which FPL will need to uneconomically dispatch higher heat rate gas turbines in Southeast Florida to maintain reliability.

Q. Has FPL made others aware of this growing imbalance between generation and load in the Southeast Florida area?

A. Yes. In the fall of 2002, upon completion of a transmission assessment, FPL identified a concern regarding the growing magnitude of the load to generation imbalance combined with the finite capability to import power into Southeast Florida for 2007 and beyond. In November 2002, FPL posted on its OASIS website information about transmission capability on its system, including information relating to concerns associated with the Southeast Florida load / generation imbalance.

As FPL continued to assess further this imbalance and generation expansion alternatives in 2007 and beyond, FPL updated this information on its OASIS website. FPL's Ten Year Site Plan, issued on April 1, 2003, highlights this issue and refers to its OASIS website where this information has been made available. FPL's concern with this growing imbalance in Southeast Florida, the need to address this issue, and the real transmission-related costs that will be incurred as a result this growing imbalance, were expressly addressed in Part I.F. of the RFP entitled "Geographic Preference."

Q. Will the addition of Turkey Point Unit 5 improve the Southeast Florida load / generation imbalance?

A. Yes.

Q. In addition to improving the growing load / generation imbalance in Southeast Florida, would the addition of Turkey Point Unit 5 otherwise enhance FPL's ability to provide reliable service in Southeast Florida?

A. Yes. There is no question that the addition of FPL's Turkey Point Unit 5 would enhance FPL's operating flexibility and reliability margin for Southeast Florida.

While FPL always strives to plan and operate its system in a reliable manner, I think it is irrefutable that, from a reliability perspective, it is preferable to have generation located in close proximity to major load centers whenever possible. The siting of at least some generation close to the load center certainly adds a level of operating flexibility and margin that contributes to increased reliability.

Moreover, siting generation near load reduces the risk associated with having to construct transmission facilities that could be necessary to move power from remote locations. The siting, licensing, permitting and construction of major transmission facilities can take a significant amount of time. In fact, in some instances major transmission facilities necessary to integrate certain generating options could take as long or longer than permitting and constructing the generating facility.

Q. Please discuss in general terms how the transmission assessment for this RFP was undertaken?

A. The transmission assessment for this RFP involved load flow studies and economic analyses to determine what transmission facilities and/or upgrades were necessary to integrate the proposed generation options in a reliable and cost effective manner. The Commission recognized the appropriateness of the evaluation of transmission integration costs in approving FPL's need for the Martin Unit 8 and Manatee Unit 3 plants in Docket Nos. 020262-EI and 020263-EI. Mr. Dag Reppen, FPL's independent transmission expert, discusses this analysis in his testimony.

FPL enhanced its analytical approach in this RFP by incorporating two major improvements in the economic analysis in order to better identify and consider certain costs that will ultimately be paid for by FPL's customers. These improvements address the economic impact of increased transmission system losses and increased operating costs resulting from the uneconomic dispatch of gas turbines in Southeast Florida. These improved methods of analysis for evaluating the capacity options for this RFP were applied to find the most cost-effective option for FPL.

Q. Please discuss transmission losses.

A. Transmission losses are a real cost of service borne by FPL's customers. Consideration of transmission losses is particularly important to FPL customers due to the vast geographic expanse of its service territory because moving power over long distances generally results in higher losses. Load flow simulations conclusively show that the amount of generation needed to serve a given amount of load varies depending on the electrical location and characteristics of the generator(s) serving a given load. Transmission losses increase costs because the capacity and energy that is lost must be replaced.

The transmission loss assessment is applied to all capacity options, including FPL's Next Planned Generating Unit, using the same methodology. Transmission losses can be quantified and converted to costs. The recognition of transmission losses in an RFP analysis is necessary for an accurate evaluation of cost-effectiveness. Mr. Reppen, an independent transmission expert, and Dr. Sim, discuss this analysis in their respective testimony. FPL believes that the evaluation of transmission losses is a significant enhancement to the RFP process for the benefit of our customers.

Q. Please explain how increased operating costs are an issue with respect to the load imbalance you have described?

A. FPL's customers bear increased operating costs arising from the need to operate Southeast Florida gas turbines to maintain reliability instead of other more economic generation located outside of Southeast Florida. These costs could be reduced if efficient new generation is located within Southeast Florida, or if the finite capability to import power into Southeast Florida is increased by constructing new transmission facilities. Thus, the identification and inclusion of these costs in evaluating potential generation options is appropriate and is in the interest of FPL's customers. This is another example of an improvement to FPL's RFP process and economic analysis. Mr. Reppen, FPL's independent transmission expert, discusses this analysis in his testimony.

Q. Does the addition of Turkey Point Unit 5 permanently address the load and generation imbalance in Southeast Florida?

A. No. The addition of Turkey Point Unit 5 constitutes a major improvement in the load and generation imbalance in Southeast Florida. However, continued load growth in this area will eventually require additional generation to be added in the area or an increase in import capability through the addition of new transmission facilities.

Q. Does this conclude your testimony?

A. Yes.

(Transcript continues in sequence with Volume 2.)

STATE OF FLORIDA)
CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, TRICIA DeMARTE, RPR, 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 7th DAY OF JUNE, 2004.

Tricia DeMarte

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