BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

DOCKET NO. 090505-EI
FLORIDA POWER & LIGHT COMPANY

JANUARY 13, 2010

IN RE: REVIEW OF REPLACEMENT FUEL COSTS ASSOCIATED WITH THE FEBRUARY 26, 2008 OUTAGE ON FLORIDA POWER & LIGHT'S ELECTRICAL SYSTEM

TESTIMONY & EXHIBITS OF:

J. A. STALL
G. YUPP
W. E. AVERA
T. J. KEITH

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF J.A. STALL

DOCKET NO. 090505-EI

January 13, 2010

Q. Please state your name and address.

A. My name is J.A. (Art) Stall. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by FPL Group, Inc. as Vice President, Nuclear Transition.

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

A. I am responsible for the overall strategic direction for all of FPL's nuclear assets, consisting of four nuclear units in Florida – two at Turkey Point Nuclear Plant near Florida City, Florida, (1,386 MW) and two at St. Lucie Nuclear Plant, near Jensen Beach, Florida (1,677 MW). I also hold this same responsibility for the other FPL Group nuclear plants – one unit at Seabrook Station in Seabrook, New Hampshire (1,294 MW), one unit at Duane Arnold Energy Center in Palo, Iowa (600 MW), and two units at Point Beach Nuclear Plant in Two Rivers, Wisconsin (1,036 MW).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain how Turkey Point Units 3 and 4 were prudently and properly taken off-line in response to the

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voltage fluctuations caused by the February 26, 2008 transmission event that was initiated at FPL's Flagami substation (the "Flagami Transmission Event"). My testimony will also describe the equipment issues that emerged during the outage that were independent of this event and delayed the restart of these units.

Flagami Transmission Event

Q. What caused Turkey Point Units 3 and 4 to come off-line during the Flagami Transmission Event?

A. Turkey Point Units 3 and 4 experienced automatic reactor shut downs due to the external transmission disturbance causing reduced voltage in the switchyard that connects the nuclear units to the FPL transmission system.

Q. Why was it necessary to shut down Turkey Point Unit 3 and Unit 4 due to this voltage reduction?

A. The nuclear units automatically shut down to protect safety related equipment. The reactor protection system operated as designed in response to the reduced voltage in the switchyard. The set point requirements for the 4 KV bus under-voltage relays are contained within the Nuclear Regulatory Commission ("NRC") operating licenses for the Turkey Point nuclear units. These requirements are very important to nuclear safety. Allowing an under-voltage condition to continue would result in a loss of flow from the reactor coolant pumps and an increase in reactor coolant temperature. This increase in reactor coolant temperature could result in damage to the nuclear fuel and to reactor coolant pump motors. Thus, it is important that the reactor units be set to automatically and promptly come off-line in undervoltage conditions.

Q. Did the Turkey Point Units come off-line as designed and in accordance with the NRC mandated undervoltage set points?

A. Yes. The Turkey Point Units came off-line exactly as designed and in accordance with the NRC mandated undervoltage set points that are included in the NRC operating licenses for Turkey Point Units 3 and 4.

Q. How long does it typically take to bring a nuclear unit back on line after an unplanned undervoltage condition such as the one caused by the Flagami Transmission Event?

A. A single nuclear unit can be brought back on line in as little as 24 hours after a plant shut down, and certainly the Company may set such timeframe as a goal, but typically it takes approximately 48 hours to bring a single unit back on line after an unexpected plant shut down. Restarting two nuclear units following an unexpected shutdown of both units is certainly more challenging than restarting a single unit. This unique set of circumstances certainly lengthens the typical 48 hour timeframe that would be required to restart a reactor following an unplanned shutdown.

In any case, a sufficient amount of time is necessary to restart equipment that was shut down and to perform all tests required by the NRC operating licenses before it can return to service. Additionally, it is FPL's and standard nuclear industry practice to provide special training to plant operators immediately prior to plant start up using a plant-specific control room simulator, which adds incremental time to the plant startup sequence after an unplanned reactor shutdown.

Q. Can unrelated equipment issues delay restart?

Yes. It is not uncommon for unrelated equipment issues to delay restart. That was the case for Unit 3 following the Flagami Transmission Event: Unit 3 would have been able to return to service in approximately 48 hours, but for certain unrelated equipment issues that had to be addressed first.

Q. Please describe the equipment issues that extended the outage for Unit 3.

A. The Unit 3 outage was extended to repair the Rod Position Indication ("RPI") system that had previously malfunctioned in October 2007. FPL had obtained permission from the NRC to defer RPI repairs until the next unit shutdown in order to minimize the overall outage time for Unit 3. There was also a condition at Unit 3 associated with a reactor protection under-voltage time delay relay that was identified to be outside its acceptance criteria for calibration. This relay was replaced in conjunction with the RPI system repair and did not contribute additional time to the Unit 3 outage duration.

Q. Could FPL have restarted Unit 3 without repairing the affected RPI system?

A. No. In January 2008, at FPL's request, the NRC amended the Unit 3 operating license to allow FPL, as an interim measure, to continue operating the plant contingent upon a commitment to repair the RPI system the next time the unit shut down. This allowed FPL to avoid additional outage time in 2008, but meant that when Unit 3 was shut down in response to the Flagami Transmission Event, FPL was required by the Unit 3 NRC operating license to implement the RPI system repair.

Q. Please describe the steps FPL took to minimize the outage time associated with repairing the RPI system.

A. When a nuclear unit is shut down, FPL initiates processes to minimize the time the unit is off-line without compromising safety. There are multiple work crew shifts working 24 hours a day, 7 days a week to minimize the time a unit is off-line. Additionally, during outages, FPL staffs a nuclear Outage Command Center at the plant to provide detailed management oversight of all of the work being performed on the unit. Because the RPI system repair was a known required repair in the event of a unit shutdown, the work orders, planning, and materials necessary to perform the work were already in place. This allowed work to proceed as soon as it was safe for plant staff to access the Unit 3 containment building to complete the RPI system repairs.

It should be noted that the containment building is a challenging work location for plant staff because of high air temperatures and the need for advance planning to minimize occupational radiation dose. This makes planning and execution of the work considerably more difficult and time-consuming when compared with work in more accessible areas of the nuclear plant or compared to work in fossil-fueled power plants that do not present heat and radiation exposure considerations.

Q. **Would FPL ultimately have experienced the same amount of outage time to repair the RPI system during any unexpected outage as was incurred following the Flagami Transmission Event?**

A. Yes. In October 2007, Unit 3 was in power ascension at 30 percent power when the initial RPI system issue was discovered. Had FPL been required to shut down Unit 3 at that time to implement the RPI repair, replacement power costs would have been incurred for the necessary outage time. As noted, FPL had to commit to the NRC to implement the RPI system repair during the next outage. The same amount of time was required to implement the RPI repair following the Flagami Transmission Event.

Q. **What extended the outage for Unit 4?**

A. When Unit 4 was returning to service, the water level in one of the four steam generators exceeded 75%. Plant operators initiated a manual reactor shutdown as required by plant procedure. The plant was shut down safely after the manual reactor shutdown.

Q. **What influences the water level in the steam generators?**

A. The main generator loading rate impacts the steam generator water level and fluctuations. The loading rate is governed by a complex interaction of various plant conditions. Because of this complexity, a reactor shutdown because of high steam generator water level occurring during plant restart is not an unusual event.

Q. What was the duration of the outages for Unit 3 and Unit 4?

A. The total outage duration, including the equipment issues that emerged independently of the transmission incident, was approximately 158 hours for Unit 3 and 107 hours for Unit 4.

Q. Are these types of outage durations unusual to you based on your experience in the nuclear industry?

A. No. While our goal is to run the nuclear units for their entire 18-month fuel cycle in order to maximize the fuel cost savings for customers, this is not always possible. Indeed, nuclear industry experience is that most units will have one or more unscheduled shutdowns during a fuel cycle. The fact that unscheduled shutdowns occur is a function of the complex technology used in nuclear generating plants and conservative operating philosophies used in their operation. Unscheduled shutdowns are not evidence of problems or deficiencies in the design or operation of the nuclear units. Rather, those shutdowns demonstrate that safety systems are working properly (in the case of automatic plant shutdowns, such as triggered both Units 3 and 4 in the Flagami Transmission Event) and that plant operators are trained to and exhibit the right behaviors to conservatively shut a nuclear unit down (in the case of manual plant shutdowns, such as described above for Unit 4).

Q. Did FPL prudently respond to the automatic reactor shutdowns at Units 3 and 4 that resulted from the Flagami Transmission Event?

A. Definitely. FPL's top priority is safe operations at all of its nuclear plants. The units automatically came off-line as intended and, indeed, as required by the NRC operating licenses for Units 3 and 4, in response to voltage fluctuations. FPL then took prudent and conservative measures to investigate, inspect, and analyze system components prior to safely restarting both units.

Q. Did the NRC identify any issues or take any enforcement action against FPL arising out of the Unit 3 and 4 outages arising from the Flagami Transmission Event?

A. No. The NRC had no issues with the outages or with the restart of both units.

Q. How did the overall generation performance of Units 3 and 4 compare to industry average for 2008?

A. The generation performance of both Turkey Point Units 3 and 4, as measured by the capacity factor and equivalent availability factor, were both above average in 2008. The combined capacity factor for Units 3 and 4 in 2008 was better than the average nuclear capacity factor ("NCF") for U.S. nuclear units. Specifically, the 2008 NCFs for Units 3 and 4 were 100.86 and 85.97, respectively. This is an average of 93.41, which is substantially above the industry average NCF of 89.97.

The combined equivalent availability for Units 3 and 4 in 2008 also was better than the 2008 average equivalent availability factor ("EAF") for U.S. nuclear units. Specifically, the 2008 EAFs for Units 3 and 4 were 97.84 and 83.44, respectively. This is an average of 90.64, which is more than a full percentage point above the industry average EAF of 89.40.

These statistics illustrate that, in spite of the unexpected outages that were initiated by the Flagami Transmission Event, FPL's customers received the benefit of considerably more low-cost nuclear-generated energy in 2008 than they would if Units 3 and 4 had performed at industry-average levels. This strong performance at Turkey Point has surpassed Turkey Point NCF and EAF performance in recent years, and this improvement is continuing, as evidenced by the fact that Unit 4 ran for 376 days during the past operating cycle without a forced outage, and the recent refueling and maintenance outage on Unit 4 was accomplished within the planned budget and schedule for the work.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 090505-EI

JANUARY 13, 2010

Q. Please state your name and address.

A. My name is Gerard J. Yupp. My business address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

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

A. I am employed by Florida Power & Light Company (FPL) as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a detailed explanation of FPL's Replacement Power Cost (RPC) calculation for the Flagami Transmission Event ("the event") that occurred on February 26, 2008.

Q. Have you prepared or caused to be prepared under your supervision, direction and control any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits included in Appendix I:

- GJY-1 – Description of Units
- GJY–2 - February 2008 Schedule A4 Heat Rate Data
- GJY-3 - February 2008 Schedule A4 Fuel Cost Data
- GJY-4 - February 2008 Schedule A4 Fuel Consumption Data
- GJY-5 – Blended Fuel Cost Calculation

- GJY-6 – Peaking Units Production Cost Calculation
- GJY-7 – System Average Cost Adjustment Calculation
- GJY-8 – Total Fuel Cost Utilizing Adjusted System Average Cost
- GJY-9 – Purchased Power Cost

Q. Please describe the components of FPL's RPC calculation.

A. FPL's RPC calculation reflects (1) costs associated with replacement fuel that was required to off-set the loss of generation that occurred as a result of the event; and (2) costs associated with off-system power purchases that FPL executed immediately following the event.

Q. What is the time frame that provides the basis for FPL's calculation of the cost of replacement fuel that was required to off-set the loss of generation that occurred as a result of the event?

A. FPL based its replacement fuel cost calculations on the 8-hour period immediately following the event.

Q. Why does FPL believe that the appropriate measure of replacement fuel costs attributable to the event is captured in the 8-hour period immediately following the event?

A. The 8-hour period immediately following the event covers the entire time frame during which the event had a significant impact on FPL's ability to operate its generating system and, as a result, FPL had to run its expensive peaking units in order to meet system load requirements. As discussed by FPL witness Stall, FPL's Turkey Point nuclear units (Units 3 and 4) remained off-line beyond that period due to startup requirements and operational issues that are unique to nuclear plants. For the reasons discussed by FPL witness Avera, however, it would be unfair to FPL and serve as a major disincentive to the construction and operation of low fuel-cost generating technologies such as nuclear, solar and wind if FPL were to be penalized for replacement power costs associated uniquely with Turkey Point Units 3 and 4 that are not a result of any imprudence in the operation of those units. Therefore, FPL has calculated replacement fuel costs for this 8-hour period, based on what its system average fuel costs would have been in that period if all generating resources were available and able to operate.

Q. What peaking units did FPL run in response to the Flagami Transmission Event?

A. FPL ran peaking units at its Fort Lauderdale, Port Everglades and Fort Myers sites. A description of these sites is shown in Exhibit GJY-1.

Q. How did FPL calculate the cost of running these peaking units?

A. The cost of running these peaking units was calculated utilizing data from FPL's February 2008 A4 Schedule, as filed with the Commission, and actual MWh production from these units during the 8-hour period immediately following the event. Specifically, heat rate, fuel price and fuel consumption data from Schedule A4 were utilized to develop the generation cost of each site of peaking units on a dollar per MWh basis. This data is shown in Exhibits GJY-2 through GJY-4. Because the Fort Lauderdale/Port Everglades peaking units are capable of burning natural gas or light fuel oil, FPL calculated a blended fuel price for each site based on the MMBtu consumption of natural gas and light fuel oil during the month. This methodology ensured that the fuel price used to determine the generation cost was representative of the proportion of each fuel utilized during the month at each site. This calculation is shown in Exhibit GJY-5. The Fort Myers peaking units burn light fuel oil only; therefore a blended price calculation was not necessary for these units. Multiplying these fuel prices times the respective heat rate for each site yielded production costs on a dollar per MWh basis for each site. Production costs, by site, are shown in Exhibit GJY-6.

Q. What was the total cost of running FPL's peaking units after the event?

A. In order to determine the total cost of running FPL's peaking units after the event, FPL multiplied the MWh production from each site by the production cost ($ per MWh basis) for each site. As shown in Exhibit GJY-6, the total system cost of running FPL's peaking units in response to the event was $1,992,270.

Q. How did FPL use the total cost for running the peaking units to determine replacement fuel costs?

A. To calculate replacement power costs resulting from generating resources being unavailable, one has to net the cost that would have been incurred if those generating resources had been available against the actual cost incurred. The figure of $1,992,270 represents the total system cost incurred for running the peaking units in the 8-hour period immediately following the event. Had the event not occurred, FPL would have generated the 11,430 MWh (Exhibit GJY-6) with other generation resources. To calculate the total replacement fuel cost, the cost FPL would have incurred to generate the 11,430 MWh if the event had not occurred must be netted against the total cost for the peaking units.

Q. What cost basis did FPL use for comparison to its peaking units to determine the net replacement fuel costs?

A. FPL used system average cost as a basis for comparison to the peaking units to determine the net cost of replacement fuel.

Q. Why did FPL use its system average cost for comparison purposes?

A. Utilizing the system average cost distributes the effect of the lost generating capacity across the entire fleet of generation, as opposed to basing the calculation on one specific type of unit. This is consistent with the testimony of FPL witness Avera that it would be unfair and create adverse incentives if the net cost of replacement fuel were based exclusively on the Turkey Point nuclear units.

Q. Did FPL adjust the system average cost reflected in the A Schedules for the purpose of the replacement fuel cost calculation?

A. Yes. Because the system average cost that FPL filed in the February 2008 A Schedules included higher overall fuel costs due to the outages of Turkey Point Nuclear Units 3 and 4, FPL adjusted its system average cost to account for these outages. In other words, had the outages at Turkey Point 3 and 4 not occurred, FPL's system average cost would have been lower in February 2008. Therefore, FPL adjusted its system average cost for February 2008 to account for these outages.

Q. How did FPL make this adjustment to the system average cost for

February 2008?

A. FPL adjusted its system average cost for February 2008 to account for the lost MWh production from Turkey Point Units 3 and 4. Turkey Point Units 3 and 4 would have generated approximately 118,783 MWh from 13:10 on February 26, 2008 through the end of the month (82 hours and 50 minutes). Other units on FPL's system were required to replace this generation. FPL calculated a replacement generation cost on a dollar per MWh basis utilizing the actual mixture of natural gas, light fuel oil and heavy fuel oil from the February 2008 Schedule A3 (Exhibits GJY-7). This generation cost was then multiplied times the 118,783 MWh to yield the fuel costs that FPL incurred in absence of the nuclear units. This figure was netted against the cost of fuel for the same MWh production for Turkey Point Units 3 and 4. The difference was subtracted from FPL's total fuel expenditures on Schedule A3 and that figure was divided by the total MWh of generation for the month on Schedule A3. This process resulted in an adjusted system average cost of $51.32/MWh, or $1.30/MWh less than the original Schedule A3 value. The calculation formulas are shown on Exhibit GJY-7 under the sections entitled "Cost Impact Calculation" and "Adjusted System Average Cost".

Q. **What was the cost of generating the 11,430 MWh with the adjusted system average cost?**

A. As shown on Exhibit GJY-8 under "Total Fuel Cost Utilizing Adjusted System Average Cost", the total system cost was $586,588.

Q. **What is the replacement fuel cost that FPL incurred to run its peaking**

units?

A. Netting the $586,588 against the $1,992,270 (cost of running peaking units) yields a total system replacement fuel cost value of $1,405,682.

Q. Please provide the details of the costs associated with off-system power purchases that FPL secured as a result of the event.

A. Immediately following the event, FPL began to purchase off-system power to help off-set the generation that was lost as a result of the event. FPL purchased a total of 5,214 MWh from six different entities throughout the afternoon/evening of February 26, 2008. FPL incurred total purchased power costs of $885,935 ($169.91/MWh), including a capacity payment to one entity. If the event had not occurred, FPL would have produced the 5,214 MWh with its own generation. Multiplying the adjusted system average cost by the 5,214 MWh yields a total cost to produce the power of approximately $267,582. Therefore, the net cost differential of the purchases that FPL made in response to the event was $885,935 minus $267,582, or $618,353. The details of the purchased power cost calculations are shown in Exhibit GJY-9.

Q. What is the total RPC that FPL calculated?

A. The total system RPC is $2,024,035. This total includes $1,405,682 of replacement fuel costs and $618,353 of purchased power costs.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF WILLIAM E. AVERA

DOCKET NO. 090505-EI

January 13, 2010

Q. Please state your name and address.

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

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

A. I am employed by Financial Concepts and Applications, Inc. ("FINCAP"), a firm engaged in financial, economic, and policy consulting to business and government. I am the President of FINCAP.

Q. Please describe your educational background and professional experience.

A. I received a B.A. degree with a major in economics from Emory University and a Ph.D in economics and finance from the University of North Carolina at Chapel Hill. I have held the Chartered Financial Analyst (CFA®) designation for 30 years. 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.

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"), as well as 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 42 states. I have testified in over 300 regulatory cases, including several before the Florida Public Service Commission ("FPSC" or "the Commission").

In 1995, I was appointed by the PUCT, with the approval of the Governor, to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of

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 (now the CFA Institute), the Financial Analysts Review, and local financial analyst societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. 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 have also served as an officer of various other professional organizations and societies.

I have extensive experience with issues of fuel and purchased power recovery, having led the PUCT staff review of the fuel adjustment clauses in Texas. Since leaving PUCT I have been involved in a variety of issues relating to fuel and purchased power recovery as a consultant and expert witness for regulatory agencies, consumer groups, and utilities.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to examine the proper regulatory treatment of the Replacement Power Cost ("RPC") arising from the February 26, 2008 transmission event at Florida Power & Light Company's ("FPL" or "the Company") Flagami substation (the "Flagami Transmission Event"). My analysis is based on my education and experience in areas of regulatory policy, finance, and economics.

Q. Please summarize the conclusions of your testimony.

A. My testimony demonstrates that, from the perspective of sound economics and regulatory policy, the calculation of RPC should recognize that FPL recovers power costs without profit and avoid creating any disincentive to invest in generation alternatives that have low fuel costs, such as nuclear, solar and wind. Basing the net cost of replacement fuel exclusively on the Turkey Point nuclear units would be unfair and result in adverse incentives for energy efficient technologies. The RPC calculation proposed by FPL witness Gerard J. Yupp is fair to FPL's customers and investors while avoiding disincentives for utilities to invest in energy efficient and environmentally beneficial generation alternatives.

Mr. Yupp's calculation is consistent with the economic logic of fuel recovery based on system average costs. His approach would also avoid penalizing FPL for investing in nuclear power with its lower fuel cost, the benefits of which are passed on to FPL's customers. As described in the testimony of FPL witness J. A. (Art) Stall, the Flagami Transmission Event caused Turkey Point Units 3 and 4 to automatically come offline as they are required to do. Turkey Point's costs should not be used exclusively in calculating the RPC, because 100% of the benefits of low nuclear fuel costs are passed on to FPL's customers. If this low nuclear fuel cost is used as a backdoor way to penalize FPL for an outage that was unrelated to its nuclear operations, a clear message will be sent to investors in FPL and other Florida electric utilities that investing in low fuel cost alternatives has become a more risky, asymmetrical proposition.

If low nuclear fuel costs are used exclusively to calculate the RPC for an outage that is entirely *unrelated to nuclear operations*, the *larger the cost differential from the system average*, the greater the penalty of disallowance to shareholders. Moreover, this increased risk does not just apply to nuclear capacity, but would apply equally to any generating resource with fuel costs significantly below the system average. This is obviously a perverse incentive given the efforts of the FPSC and Florida leaders to encourage energy-efficient and renewable technologies due to their benefits for the environment and economy of Florida. A balanced approach to RPC recovery based on system average costs is consistent with Florida's policy that encourages utilities to invest in the high capital cost alternatives of nuclear, wind, and solar, which have lower energy costs and environmental benefits. This energy efficiency policy benefits FPL's customers as well as the environment and the economy of Florida.

Mr. Stall explains that the outage of Turkey Point was triggered by the Flagami Transmission Event, and was consistent with Nuclear Regulatory Commission ("NRC") requirements for plant operations and not the result of any improper or inappropriate actions in the operation of these units. FPL then took appropriate, prudent actions to return the units to service as promptly as possible. Therefore, Mr. Yupp's calculation of RPC properly includes only the outage time related to the Flagami Transmission Event. It would be both unfair and create additional disincentives to invest in nuclear generation if the additional outage time required to address equipment issues at Turkey Point were included in the calculation of the RPC.

<u>Regulatory Policy on Power Cost Recovery</u>

Q. Are there established regulatory policies related to the recovery of replacement power costs?

A. Yes. A fundamental tenet of the regulatory compact is that the utility is entitled to an opportunity to recover from customers all reasonable and necessary costs prudently incurred in providing service. Under regulatory policy in Florida (as in most state and federal jurisdictions), a utility is allowed to recover prudently incurred fuel and purchased power costs without profit or loss.

Under Florida's fuel and power adjustment clauses, a utility has an opportunity to recover its actual fuel costs. The best outcome for the utility is that the dollars it has paid are fully recovered from customers, with no opportunity for gain. On the other hand, if some of the utility's expenditures are deemed to have been imprudent, then those costs are not recovered from customers. Thus, utility investors see an asymmetric risk exposure in clause recovery, with no upside opportunity and a potentially large downside.

Q. Has the FPSC recognized the importance of the economic incentives inherent in fuel and purchased power recovery?

A. Yes. This Commission has been a national leader in recognizing that the rules for fuel and purchased power recovery create economic incentives for efficient utility behavior. In 1979, when I was leading an effort at the PUCT to introduce incentives into the fuel and purchased power mechanism, I visited with senior staff and commissioners in Florida to learn from the policies implemented here. The FPSC has continued to be a leader in mobilizing incentives.

Q. What is the effect of Florida's power cost recovery mechanism on the economics of generation alternatives that have low fuel cost?

A. The asymmetry of the risk exposure I described earlier is heightened. The benefits of low fuel costs are passed on directly to consumers by reducing the average power cost in the bills they pay. However, the low fuel costs of those generating resources increase the economic exposure of the utility and its investors to a disallowance if the FPSC finds that one of those resources was not operating due to imprudence. Moreover, since the most fuel-efficient generating alternatives have high capital costs, utility shareholders are especially sensitive to any increased risk of disallowance since they have huge amounts of money on the line. In other words, the same low fuel costs that benefit customers may also heighten the risk associated with power cost disallowances for investors. This is because the potential differential between the cost of replacement power and the lost low-cost generation source is large, which exposes shareholders to the potential for greater disallowed energy costs than from a higher fuel cost alternative.

Exposure to high replacement power costs when the utility is found to have operated a low fuel cost resource in an imprudent manner is an accepted part of the regulatory compact under which utilities in Florida operate. Investors understand that they are exposed to this risk when plant operations fail the prudence test. However, if the benefits associated with low fuel cost resources were used to increase the RPC when there is an outage unrelated to the operation of the generating plants -- such as an outage caused by a transmission disturbance (as Mr. Stall explains was the case in the Flagami Transmission Event) -- then shareholders would be exposed to an additional risk due to the very energy efficiency that the FPSC regulatory policy favors. In short, the more fuel-efficient the resource, the steeper the RPC penalty from an outage unrelated to plant operations. Investors have not included the additional risk of disallowances unrelated to plant operations in the return they require from securities issued by FPL. If investors are sent a signal that they are exposed to large disallowances from events unrelated to the operations of low fuel cost generation resources simply due to the spread between the fuel-efficient cost and replacement power, the cost of capital associated with investment in low fuel cost generation will increase.

If the RPC for a transmission outage were calculated based exclusively on the low fuel cost generating resources that happened to be affected by the outage, then investors' risk exposure would be increased even in those cases where there has been no imprudence in operating those resources. This would create a clear disincentive to invest in fuel-efficient generation alternatives because their low cost would increase the potential penalty from unrelated outages. For example, using the low fuel cost of Turkey Point Units 3 and 4 as the sole basis to compute RPC in this case would unfairly increase the penalty for the Flagami Transmission Event even though that outage was unrelated to the operation of the nuclear units. In contrast, calculating the RPC based on system average costs, as Mr. Yupp has done, does not focus the penalty on FPL's investment in low fuel cost generation and thus avoids a disincentive to the development of these important resources.

Q. Is the use of system average power costs consistent with FPSC power cost recovery policy?

A. Yes. Under FPSC regulatory policy, customers' bills reflect system average power costs. When customers use more or less electric energy, their bills go up or down by system average power costs. Consistent with this policy, the RPC from a transmission outage that causes a generating plant to become unavailable should also be based on system average power costs. The fact that the Flagami Transmission Event happened to affect the operation of a nuclear generating unit with low fuel cost does not justify ignoring system average power cost and instead focusing the RPC calculation exclusively on the operating costs for those nuclear units.

Q. What would be the effect of focusing on the low fuel cost resource, rather than using system average power costs, in calculating RPC?

A. Utilities would be discouraged from investing in nuclear and other low fuel-cost generation because investors would be exposed to RPC refunds whenever those facilities are forced offline for reasons unrelated to their operations. As indicated earlier, such an outcome would increase the risk exposure of investors beyond those ordinarily associated with operating low cost generating resources because they would be subject to increased disallowances due to transmission disturbances and other events unrelated to the specific operations of these generating facilities. This disincentive to efficiency is contrary to the regulatory policy of the FPSC fuel and purchased power recovery.

Reasonableness of FPL's Proposed RPC Calculation

Q. Why is it important not to penalize FPL for the time Turkey Point Units 3 and 4 were unavailable due to the Flagami Transmission Event?

A. As explained by Mr. Stall, FPL responded prudently to return Turkey Point Units 3 and 4 to service as promptly as possible. The circumstances that extended the outages were not related to the Flagami Transmission Event and were not the result of any improper or inappropriate actions on FPL's part. It would be unfair to FPL and serve as a major disincentive to the construction and operation of low fuel-cost generating technologies such as nuclear, solar and wind if FPL were to be penalized for replacement power costs that are not a result of any imprudence in the operation of Turkey Point Units 3 and 4.

As discussed earlier, adding to the risk of disallowances associated with fuel efficient generating resources creates disincentives that are contrary to sound regulatory policy. Similarly, increasing the penalty because of legitimate operational issues unique to Turkey Point and unrelated to the triggering transmission disturbance, would heighten the disincentive and would unfairly penalize investors. Therefore, FPL has calculated replacement fuel costs for the 8-hour period during which the Flagami Transmission Event had a significant impact on the company's ability to operate its generation system and based that calculation on what its system average fuel costs would have otherwise been during that period if all generating resources were available and able to operate.

Q. Have customers been well-served by FPL's investment in Turkey Point Unit's 3 and 4?

A. Yes. FPL's customers have enjoyed the benefits of the low fuel cost associated with the Turkey Point nuclear units for many years in the lower fuel adjustment they have paid in their bills. As explained by Mr. Stall, Turkey Point Units 3 and 4 have performed in a safe and reliable manner, exceeding industry averages for nuclear capacity factor and equivalent availability in 2008 even with the outage triggered by the Flagami Transmission Event and the equipment issues unrelated to the triggering transmission disturbance.

Q. Do consumers and the economy of Florida benefit from avoiding disincentives for investing in low fuel cost alternatives?

A. Yes. The policy of the FPSC and other agencies of Florida State Government has been to encourage investment in nuclear power and other energy-efficient generation alternatives. Development of low fuel cost alternatives helps moderate the fuel and purchased power costs that customers pay in their bills. Since Florida is remote from conventional fuel sources, avoiding the cost of purchasing and transporting these fossil fuels is an obvious and direct benefit to customers. In addition, minimizing the burning of fossil fuels helps protect and improve the environmental quality that brings visitors and new residents to this beautiful state. Moreover, since low energy cost alternatives generally require extensive upfront capital investment in facilities located inside the state, these energy-efficient alternatives generate economic activity so badly needed by Florida workers and communities. The efforts of the FPSC and other leaders in Florida to encourage fuel-efficient investment in the state would be undermined if investors are exposed to unwarranted RPC penalties when an outage is caused by circumstances other than imprudent plant operations.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 090505-EI

January 13, 2009

Q. Please state your name and address.

A. My name is Terry J. Keith and my business address is 9250 West Flagler Street, Miami, Florida 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as Director, Cost Recovery Clauses in the Regulatory Affairs Department.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present to the Commission viable options for refunding customers the replacement power costs resulting from the Flagami Transmission Event on February 26, 2008.

Q. What does FPL believe would be the most appropriate method to refund customers the replacement power costs associated with the Flagami Transmission Event?

A. FPL believes that it would be most efficient and consistent with fuel cost recovery ("FCR") precedent to reflect this refund in the 2010 net true-up, where it would serve to reduce the 2011 FCR factors for all customers.

Q. What method would FPL recommend if the Commission prefers that FPL make a one-time credit to customers for these replacement power

costs?

A. If the Commission prefers that FPL make a one-time credit, then that credit should be issued to FPL's customers of record during the first billing cycle beginning 60 days after the Commission decides the credit amount. The credit for each customer should be based on the customer's consumption which is billed in that billing cycle. This is the most efficient means to implement a one-time credit and has been utilized by the Commission recently in Docket No. 080001-EI (Turkey Point Unit 3 pressurizer piping incident) and Docket No. 090001-EI (2009 net true-up over-recovery).

In the case of a one-time credit based on the customers' current consumption, FPL is able to modify the programs developed for the refund of replacement power costs associated with the Turkey Point Unit 3 pressurizer piping incident, which reduces the cost to implement this type of credit to $70,000 and requires 60 days of implementation time. By contrast, the original cost to implement the refund of the Turkey Point Unit 3 pressurizer piping incident was $220,000 and required three months to implement.

Q. *Didn't the Commission express reservations about the current* consumption method in the case of the one-time credit associated with the 2009 net true-up over-recovery?

A. Yes. However, the situation in this case is significantly different. Unlike the one-time refund of the $365 million 2009 net true-up over-recovery, this refund is based on a significantly smaller dollar amount and was incurred over a very short period of time; not 12 months as was the case with the refund of the 2009 net true-up over-recovery.

Q. Does FPL believe that it would be appropriate to implement the one-time credit based on 12 months of consumption?

A. No. FPL does not believe that there is any practical or equitable reason why the one-time credit contemplated in this proceeding needs to be calculated based on 12 months of consumption. This approach is more costly and would delay the implementation of the credit due to the amount of time required to perform the necessary computer coding and integration testing.

Q. Please describe the efforts required to implement a one-time credit to customers.

A. First, one has to recognize that FPL's Customer Information and Billing systems contain a massive amount of data and the integrity of these systems must be maintained at all times to ensure that customer bills are accurate. Thus, exception transactions, such as one-time credits, generally require ad-hoc programming and significant testing. Due to the age of our current Customer Information and Billing systems, even a minor change requires full integration testing based on approximately 1,000 different billing scenarios. This testing requires approximately six weeks to execute. Because the systems are processing so many transactions daily, there are very limited windows of time within the day to perform additional programming and testing. This has the effect of stretching out the overall period of time that is required to implement any type of change to these systems. In addition, previously planned enhancements or changes must be scheduled independently of each other because of time constraints and increased difficulty in programming and testing more than one change simultaneously.

Q. Please explain why implementing a one-time credit based on 12 months of historical consumption would further complicate the refund process.

A. Calculating 12 months of consumption is not the same as reading 12 rows of data and then adding them together. The data contained in the Customer Information and Billing systems database captures all exceptions that have occurred to customer accounts. One example of an exception is where an account has been rerouted and more than 12 billing records are rendered in a one-year period. Another example is where an account was recently connected and less than 12 billing records are rendered in a one-year period.

Each type of exception must be identified and a determination must be made as to whether to include or exclude the impact of the exception in the credit calculation. Therefore, to ensure that the consumption data for each customer for each of the 12 months is accurate, all potential billing exceptions must be identified and logic must be developed to address every potential exception. This requires additional coding, new programs and significant processing time to make historical 12-month consumption calculations for each customer. 225,000 billing records must be processed an additional 12 times each day (2.7 million additional calculations daily) in order to aggregate historical billing consumption.

Q. How much time and cost would be required to implement a one-time credit based on 12 months of consumption?

A. The complexities I just described would cause the implementation to take approximately three months, at an estimated cost of $120,000.

Q. If the Commission were to direct that the one-time credit be based on 12 months of historical consumption, how should that method be applied?

A. The refund would need to be made in the August 2010 billing cycle, at the earliest. The credit calculation would be based on each customer's consumption for 12 consecutive billing periods ending with the July 2010 billing cycle. Only customers of record in the August 2010 billing cycle would receive the refund.

Q. Will the total amount of money to be refunded to customers differ depending on the credit methodology approved by the Commission?

A. No. The total amount of money refunded to customers will be the same regardless of whether the Commission reflects the credit in the 2010 net true-up or requires a one-time credit to customers.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX I

DOCKET NO. 090505-EI

FPL WITNESS G. YUPP

EXHIBITS GJY-1 THROUGH GJY-9

Unit	Description
LG1	Site 1 – Fort Lauderdale Gas Turbines Units 1-12 (28.5 MW per Unit)
LG2	Site 2 – Fort Lauderdale Gas Turbines Units 13-24 (28.5 MW per Unit)
PGT	Site 3 – Port Everglades Gas Turbines Units 1-12 (28.5 MW per Unit)
FGT	Fort Myers Gas Turbines Units 1-12 (46 MW per Unit)

Unit	Heat Rate (MMBtu/MWh)
LG1 HR	17.716
LG2 HR	16.450
PGT HR	17.727
FGT HR	13.265

Unit	Nat Gas ($/MMBtu)	#2 Oil ($/MMBtu)
LG1	9.94	14.33
LG2	9.94	14.33
PGT	9.94	12.10
FGT	Not Applicable	13.25

Unit	Nat Gas MMBtu	#2 Oil MMBtu	Total MMBtu	Nat Gas %	#2 Oil %
LG1	86,334	714	87,048	99.2	0.8
LG2	52,402	3,444	55,846	93.8	6.2
PGT	42,141	111	42,252	99.7	0.3

Nat Gas % = Nat Gas MMBtu / Total MMBtu
#2 Oil % = #2 Oil MMBtu / Total MMBtu

Unit	Formula	Blended Fuel Cost ($/MMBtu)
LG1 BFC	(.992 * 9.94) + (0.008 * 14.33)	9.98
LG2 BFC	(.938 * 9.94) + (0.062 * 14.33)	10.21
PGT BFC	(.997 * 9.94) + (0.003 * 12.10)	9.95
FGT FC	Not Applicable	Not Applicable

Fuel Cost (FC) = (Nat Gas % * Nat Gas Cost) + (#2 Oil % + #2 Oil Cost)

Hourly Unit Production Cost

Unit	Formula	Production Cost ($/MWh)
LG1	LG1 HR * LG1 BFC	176.81
LG2	LG2 HR * LG2 BFC	167.95
PGT	PGT HR * PGT BFC	176.38
FGT	FGT HR * FGT FC	175.76

Hourly MWh Production

Hour Ending	LG1 MWh	LG2 MWh	PGT MWh	FGT MWh	Total MWh
1400	173	178	180	532	1,063
1500	262	321	302	559	1,444
1600	267	335	307	550	1,459
1700	270	338	309	559	1,476
1800	276	347	305	559	1,487
1900	289	356	305	550	1,500
2000	292	357	308	550	1,507
2100	287	297	169	485	1,238
2200	59	72	13	112	256
Total	**2,175**	**2,601**	**2,198**	**4,456**	**11,430**

Total Peaking Unit Production Cost

Unit	MWh	$/MWh	Cost ($)
LG1 ($)	2,175	176.81	384,562
LG2 ($)	2,601	167.95	436,838
PGT ($)	2,198	176.38	387,683
FGT ($)	4,456	175.76	783,187
Total	**11,430**	**Not Applicable**	**1,992,270**

LG1 ($) = LG1 MWh * LG1 $/MWh
LG2 ($) = LG2 MWh * LG2 $/MWh
PGT ($) = PGT MWh * PGT $/MWh
FGT ($) = FGT MWh * FGT $/MWh

Original A3 Data

Fuel	Cost	MWh	$/MWh
Heavy Oil	22,902,013	222,625	102.87
Light Oil	840,820	4,699	178.94
Coal	12,010,604	517,794	23.20
Natural Gas	308,188,667	4,052,626	76.05
Nuclear	8,430,238	1,898,820	4.44
Total	**352,372,341**	**6,696,564**	**52.62**

Fuel Mix

Fuel	MWh	% MWh
Heavy Oil	222,625	5.20%
Light Oil	4,699	0.11%
Natural Gas	4,052,626	94.69%
Total	**4,279,950**	**100.00%**

Blended Marginal Cost

Fuel	$/MWh	% MWh	BMC $/MWh
Heavy Oil	102.87	.0520	5.35
Light Oil	178.94	.0011	0.20
Natural Gas	76.05	.9469	72.00
		Total	**77.55**

Cost Impact Calculation
Total February Turkey Point Units 3 and 4 Lost Production in MWh (717 MW per Unit)
1,434 MW * 82 hours-50 minutes = 118,783 MWh

Total Fuel Cost = 77.55 $/MWh * 118,783 MWh = $9,211,622

Fuel Cost for Turkey Point Units 3 and 4 = 118,783 MWh * 4.44 $/MWh = $527,397

Net Cost Impact Compared to Nuclear Units = $9,211,622 - $527,397 = **$8,684,225**

Adjusted System Average Cost
Original A3 Fuel Cost – Net Cost Impact Compared to Nuclear Units = Adjusted Total Fuel Cost
$352,372,341 - $8,684,225 = $343,688,116

Adjusted Total Fuel Cost / Total System MWh = Adjusted System Average Cost
$343,688,116 / 6,696,564 MWh = $51.32/MWh

Total Fuel Cost Utilizing Adjusted System Average Cost

11,430 MWh * $51.32/MWh = $586,588

Transaction No.	Begin Time	End Time	Volume (MWh)	Total Cost	$/MWh
1	1400	2100	1,350	169,700.00	125.70
2	1500	2000	863	117,890.00	136.60
3	1400	1800	650	127,100.00	195.54
4	1500	2100	625	186,250.00	298.00
5	1400	2100	1,661	265,672.64	159.95
6	1500	2000	65	19,322.55	297.27
		Total	**5,214**	**885,935.19**	**169.91**

Note: Transaction No. 5 includes a capacity payment based on highest hourly demand.

Differential purchased power cost with $51.32/MWh adjusted system average cost =
885,935.19 – (5,214 MWh • $51.32/MWh) = $618,353