ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070098-EI
FLORIDA POWER & LIGHT COMPANY

IN RE: FLORIDA POWER & LIGHT COMPANY'S PETITION TO DETERMINE NEED FOR FPL GLADES POWER PARK UNITS 1 AND 2 ELECTRICAL POWER PLANT

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DIRECT TESTIMONY & EXHIBIT OF:

STEVEN R. SIM

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF STEVEN R. SIM

DOCKET NO. 07_____ - EI

JANUARY 29, 2007

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, and wind power 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:

Document No. SRS-1	Projection of FPL's 2007 - 2015 Capacity Needs (without New Resource Additions);
Document No. SRS-2	Additional FPL DSM Above DSM Goals: 2006 – 2015;
Document No. SRS-3	Economic Analyses of Coal Technologies;

Document No. SRS-4	Projection of FPL's 2007 – 2015 Capacity Needs: with FGPP 1 and 2;
Document No. SRS-5	The Two Resource Plans Utilized in the Analyses;
Document No. SRS-6	Fuel Cost Forecasts Utilized in the Analyses;
Document No. SRS-7	Environmental Compliance Cost Forecasts Utilized in the Analyses;
Document No. SRS-8	Economic Analysis Results for One Fuel and Environmental Compliance Cost Scenario: Generation System Costs Only;
Document No. SRS-9	Economic Analysis Results for One Fuel and Environmental Compliance Cost Scenario: Generation System and Transmission System Costs;
Document No. SRS-10	Calculation of Peak Hour Loss Cost for the Plan with Coal Compared to the Plan without Coal;
Document No. SRS-11	Calculation of Annual Energy Loss Cost for the Plan with Coal Compared to the Plan without Coal;
Document No. SRS-12	Economic Analysis Results: Total Costs and Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios;

Document No. SRS-13	Economic Analysis Results: the Plan with Coal vs. the Plan without Coal Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios;
Document No. SRS-14	Non-Fuel Cost Projections for the First 12 Months of Operation for FGPP 1 and 2; and,
Document No. SRS-15	Fuel Diversity Analysis Results: FPL System Fuel Mix Projections by Plan.

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

A. Yes. I am co-sponsoring Sections II, IV, V, VI, and VIII of the Need Study document. I also sponsor Appendices B, G, K, and N, and co-sponsor Appendix C.

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

A. My testimony addresses eleven main points. First, I briefly discuss FPL's integrated resource planning (IRP) process and note that the application of the IRP process in 2006 focused on maintaining fuel diversity in FPL's system. Second, I identify FPL's additional resource needs for 2007 - 2015, with particular emphasis on the 2012 through 2015 time period, and explain how these needs were determined. Third, I discuss why DSM cannot reasonably be expected to eliminate these resource needs. Fourth, I discuss the results of an economic analysis of several coal technologies and explain how those results support FPL's selection of the ultra-supercritical pulverized coal technology (advanced technology coal) proposed for FPL's Glades Power Park (FGPP) site. Fifth, I present an overview of the analysis approach used to evaluate the addition of the FGPP 1 and 2 advanced technology coal units to FPL's system versus the most likely non-coal competing technology, natural gas-fired combined cycle units, from both an economic and fuel diversity perspective. Sixth, I discuss two resource plans: a fuel diversity resource plan selected by FPL that includes advanced technology coal unit additions at FGPP and an alternate resource plan without coal additions that was used to evaluate the economic and fuel diversity impacts of adding FGPP 1 and 2. Seventh, I discuss FPL's use of various fuel cost forecasts and environmental compliance cost forecasts that were combined into 16 fuel cost and environmental compliance cost scenarios that were used in the analyses of the two resource plans. Eighth, I present the results of FPL's economic analyses of the two resource plans. Ninth, I present the results of the fuel diversity analyses of the two resource plans. Tenth, I discuss the negative system fuel diversity impacts that would occur if a Need Determination for FGPP 1 and 2 were not approved. Eleventh, I explain the conclusions I draw from the previously discussed analyses and summarize my testimony. The conclusion I draw from this information is that adding FGPP 1 to FPL's system by 2013, followed by the addition of FGPP 2 by 2014, is the best choice for addressing FPL's future capacity needs in the 2012 through 2015 time period and for maintaining fuel diversity in FPL's system.

I. FPL's Integrated Resource Planning Process

Q. What are the objectives of FPL's integrated resource planning process?

A. The fundamental approach used in FPL's IRP process was developed in the early 1990s and the process has been used since that time to accomplish three primary objectives: 1) determine the timing of when new resources are needed to maintain the reliability of the FPL system, 2) determine the magnitude (MW) of the needed resources, and 3) determine the type of resources that should be added. The analysis required to accomplish the first two objectives – determining the timing and magnitude of needed resources – is often referred to as the reliability assessment portion of FPL's IRP process and these analyses are relatively straightforward.

The analyses required to accomplish the third objective – determining the type of resources that should be added – is more complex and involves the consideration of both economic and what are often termed non-economic perspectives. From an economic perspective, the type of resources that should be added is primarily based on a determination of the resources that result in the lowest system 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 (cumulative present value of revenue requirements, CPVRR). The lowest total cost perspective (CPVRR) in these cases is the same as the lowest average electric rate perspective, because the number of kilowatt-hours over which the costs are distributed does not change, as would be the case when DSM resources are being examined.

However, the type of resources to be added is also influenced by considerations such as whether an option can be brought into service on FPL's system in time to meet a projected capacity need and whether a given resource option or plan is best suited to address system concerns that may have been identified in the resource planning process. While these system concerns usually have an economic component or impact, they are often discussed in non-economic terms such as percentages, etc. rather than in terms of dollars.

Q. What is meant by system concerns and how are they addressed in FPL's IRP process?

A. As previously mentioned, FPL developed its fundamental IRP approach in the early 1990s. In the intervening years FPL's IRP process has evolved in order to be able to address special system concerns that have been identified. In recent years one of those system concerns has been maintaining a regional balance between load and generating capacity, particularly in Southeastern Florida. This concern has been satisfactorily addressed for the near-term with the addition of Turkey Point 5, West County Energy Center (WCEC) 1, and WCEC 2 generating units, all in Southeastern Florida.

Another system concern is that of maintaining system fuel diversity. FPL's 2006 IRP process has directly addressed this concern and, as a result, is proposing advanced technology coal units to address FPL's next capacity needs. Maintaining, and enhancing if possible, system fuel diversity will continue to be an issue that FPL's resource planning work addresses in coming years. The issue of fuel diversity is discussed in detail in Mr. Yupp's testimony.

System concerns such as these are generally addressed in the IRP process in regard to meeting the third objective described above - determining the type of resources that should be added. The selection of resource options and resource plans for analyses is done with these system concerns in mind. Then, in conducting the analyses needed to determine which resource options and plans are best for FPL's system, both the economic and non-economic analyses are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or plan.

Q. Did FPL utilize its IRP process in the analyses that led to FPL seeking approval of a determination of need for two advanced technology coal units, one each by 2013 and 2014?

A. Yes. FPL utilized its IRP process to first determine the timing and magnitude of resource needs. It was determined that FPL's first significant resource need was in 2012 and that this resource need increased every year thereafter. Second, FPL identified resource options that could meet these needs with particular attention paid to options that could come in-service as close to 2012 as possible, and that could address the system concern of maintaining fuel diversity on FPL's system. FPL then determined the best resource options to add to both meet the resource needs and maintain system fuel diversity.

II. FPL's Future Resource Needs

Q. How did FPL decide it needed additional resources and what was the magnitude of the needed resources?

A. FPL uses two analytical approaches in its reliability assessment to determine the timing and magnitude of its future resource needs in order to continue to provide reliable electric service to its customers. The first approach is to make projections of reserve margins both for Winter and Summer peak hours for future years. A minimum reserve margin criterion of 20% is used to judge the projected reserve margins. The 20% reserve margin criterion is based on the reliability planning standard FPL committed to maintain and the Commission approved in Order No. PSC-99-2507-S-EU.

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. This again was the case in FPL's 2006 reliability assessment that was the basis for FPL's projected resource needs. Significant levels of additional resources (MW) are needed for each year beginning in 2012 to meet the Summer reserve margin criterion of 20%. (FPL also projects a relatively small 167 MW need in 2011 that FPL currently plans to meet with a short-term purchase(s), enhancements to its existing generating units, and/or additional cost-effective DSM.)

Assuming that the 2011 need mentioned above is met by a one-year purchase, the additional incremental MW needed by the Summer of 2012 is projected to be 777 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% reserve margin criterion, (777 MW/1.20 =) 648 MW if provided by a DSM-based reduction to the forecasted peak load. The similar incremental need values for the Summers of 2013 - 2015, respectively, are an additional 417 MW (supply) or

348 MW (DSM) for 2013, an additional 450 MW (supply) or 375 MW (DSM) for 2014, and an additional 639 MW (supply) or 533 MW (DSM) for 2015.

These incremental annual resource need values add to a cumulative need value for 2012 - 2015 of approximately 2,283 MW if the resource need is to be met by supply options. The corresponding cumulative resource need for the four-year period is approximately 1,903 MW if the resource need is to be met by DSM. The projections of resource needs to meet the Summer reserve margin criterion for 2012 - 2015 if the resource needs are to be met by supply options are shown in Document No. SRS-1. This document also shows that, if these levels of supply additions are added to meet the Summer needs, these additions will also easily satisfy the smaller resource needs to meet the Winter reserve margin criterion.

These projections rely upon FPL's IRP 2006 load forecast that was developed in September 2006 and used in the economic and fuel diversity analyses discussed in the remainder of my testimony. This load forecast is discussed by Dr. Green in his testimony.

III. Demand Side Management

Q. Do these projections of FPL's resource needs include all of the cost-effective DSM currently known to FPL?

A. Yes. These projections already incorporate all of the cost-effective DSM currently known to FPL. This amount of DSM includes not only FPL's current DSM Goals, but also a significant amount of additional DSM that FPL has identified as cost-effective since the DSM Goals were approved. Mr. Brandt's testimony provides detailed information regarding the DSM Goals and additional DSM amounts.

In summary, FPL now projects implementing approximately 564 MW at the generator of additional Summer demand reduction capability from 2006 through 2015 beyond FPL's current DSM Goals. The amounts of additional DSM and the DSM Goals amount are presented in Document No. SRS-2. This amount of additional DSM, plus FPL's DSM Goals, are incorporated into the projection of FPL's resource needs presented in Document No. SRS-1 and discussed above.

Q. Could FPL meet its 2012 through 2015 resource needs with DSM?

A. No. As discussed above, FPL's resource needs presented in Document No. SRS-1 already account for all of the reasonably achievable, cost-effective level of DSM for FPL between 2006 and 2015 that were presented in Document No. SRS-2. As shown in this document, FPL's DSM activities will result in approximately 802 MW at the generator (DSM Goals) plus approximately 564 MW at the generator of additional DSM beyond FPL's Goals for a total of approximately 1,366 MW of incremental DSM at the generator from 2006 through 2015, a 10-year period. In other words, FPL's reliability assessment has already captured the cost-effective DSM known to be available on FPL's system. This reliability assessment determined that FPL still needs a significant amount of additional capacity resources to meet its resource needs.

As previously discussed, if the resource needs for just the years 2012 through 2014 were to be met solely by additional new DSM resources, FPL would need to find an additional 1,371 MW of cost-effective DSM to meet these resource needs (i.e., 648 MW for 2012, 348 MW for 2013, and 375 MW for 2014). It is unrealistic to conclude that FPL could first identify, and then implement, another 1,371 MW of cost-effective, incremental DSM in the next 7 ½ years (2007 through mid-2014) to meet these needs, especially when considering that this amount of DSM is virtually identical to the maximum amount (1,366 MW) of cost-effective DSM known to FPL for the 2006 - 2015 time period, and that is already included in the projection of capacity needs. Consequently, cost-effective DSM could not meet FPL's incremental resource needs for this time period. These resource needs must be met by capacity (construction and/or purchase) additions; i.e., the system resource needs presented in this testimony are actually capacity needs and will be referred to as such in the remainder of my testimony.

IV. FPL's Selection of Advanced Technology Coal Units

Q. What evaluations of various coal technology options were conducted?

A. There were three separate evaluations of coal-based technologies that were conducted prior to FPL's filing for determination of need for its two advanced technology coal units. The first of these evaluations was conducted by FPL in 2004 and early 2005. Mr. Hicks' testimony also addresses this technology evaluation.

During this time period, FPL conducted both qualitative and quantitative analyses of coal-based technologies in order to determine what the best coal-based technology option was that could be brought into FPL's system to meet a significant capacity need and maintain system fuel diversity starting at the earliest possible date. Three coal-based technologies were examined in these quantitative analyses: circulating fluidized bed (CFB) units, integrated gasification combined cycle (IGCC) units, and advanced technology coal units. The results of these analyses led FPL to conclude that the advanced technology coal units were the best selection.

In 2006, using refined knowledge of the cost and characteristics of the various coal technologies, FPL initiated two additional analyses to check or confirm that the choice of advanced coal technology for FGPP was still the best selection for FPL and its customers. These analyses included a fourth coal technology, subcritical pulverized coal (PC). One of these "confirming" analyses was conducted solely by FPL and one was conducted by Black & Veatch (BV) in collaboration with FPL. The FPL-only analysis is discussed below. The collaborative BV and FPL analysis is briefly summarized below and is described in more detail in the testimony of Mr. Hicks who is a co-author of the report on that analysis.

Q. How was the FPL-only confirming analysis conducted?

A. FPL's analysis was an economic evaluation by FPL's Resource Assessment and Planning business unit of the previously mentioned four coal technology options: PC, CFB, IGCC, and advanced technology coal units. FPL's approach was a screening curve evaluation. This approach is commonly used in the electric utility industry to compare competing generating unit or technology options that are expected to be dispatched in a similar fashion on a utility system (i.e., to be dispatched as baseload units, or as peaking units, etc.). The approach first addresses capital costs, fixed operation and maintenance (O&M) costs, and other fixed costs over the projected life of the unit. These annual costs are calculated and then typically converted to a levelized $/kw and/or levelized $/MWH (or the equivalent cents/kwh) fixed cost that is independent of the capacity factor at which the unit will be operated. Then, using different capacity factors ranging from zero to the projected upper limit of annual availability for the unit, similar levelized $/kw or $/MWH costs for variable costs such as variable O&M, fuel, etc. are developed and added to the levelized fixed cost value to derive a levelized total cost value for each capacity factor.

The levelized total cost values for each capacity factor are then graphed for each capacity factor level considered. If a $/kw data format is used, the resulting values (cost lines) typically appear as straight lines with different starting points and slopes. If a $/MWH (or cents/kwh) data format is used, the resulting cost lines typically appear as lines curving downward from the upper left of the graph to the lower right.

Typically, one of two possible outcomes are shown by this graphic depiction of the analysis results when two (or more) competing options are analyzed:

- One option's cost line may be lower than that of the second option for all capacity factors up to a point (for example, up to a capacity factor of 50%), then the first option's cost line will be higher than that of the second option for the remaining capacity factors. This result means that the first option is the more economical option if the two options are expected to operate at capacity factors of less than 50%, but that the second option is the more economical option if the two options are expected to operate at capacity factors of 50% or greater.

- One option's cost line is lower than that of the second option for all capacity factors considered. This result means that the first option is the more economical option of the two over all possible capacity factors.

For this confirming analysis, FPL's Engineering and Construction business unit developed current cost and performance values for each of the four coal technology types in capacity increments of approximately 980 MW (i.e., similar in size to one of the advanced technology coal units). The cost and performance values for each of the four coal technologies were then utilized in the screening curve analyses. Two analyses were conducted; one without the inclusion of the cost of allowances to address each unit's sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon dioxide (CO_2), and mercury (Hg) emissions, and one with the inclusion of the allowance costs for these emissions. Although CO_2 emissions are not currently regulated, the potential costs of CO_2 allowances were included in this analysis to gauge the relative impact of potential CO_2 regulation.

Q. **What were the results of FPL's screening curve analyses?**

A. Document No. SRS-3 presents the results of FPL's screening curve analyses in a \$/MWH data format. As shown in this document, the advanced technology coal unit's cost line is lower than the cost lines for each of the other three technologies over the entire range of capacity factors in both the analysis with, and the analysis without, allowance costs. This indicates that the advanced technology coal unit is a more economical generation choice than the other three technologies for all capacity factor levels.

Q. **Was the Black & Veatch and FPL collaborative confirming analysis similar in nature to FPL's economic analysis that utilized a screening curve approach?**

A. The approach taken in this analysis encompassed both a quantitative (i.e., economic) and qualitative or technical evaluation of the same four coal technology options. In this sense, it was similar in scope to the analyses FPL conducted in 2004/2005 that initially concluded that the advanced technology coal option was the best selection for FPL's system. In both the economic and qualitative portions of the BV and FPL evaluation, the most current technical information regarding the four coal technology options was utilized.

In the economic portion of the BV and FPL collaborative analysis, a similar approach (labeled as a busbar cost analysis) to that utilized in the FPL-only confirming study was used and a similar conclusion was reached; i.e., the advanced technology coal technology option is the most economic option for FPL's system of the four technologies over all capacity factors.

As previously mentioned, Mr. Hicks' testimony addresses the BV and FPL confirming analysis in more detail.

Q. What conclusions did FPL draw from the two confirming analyses?

A. The results of the confirming analyses conclusively show that the advanced technology coal option is the most economical choice by a substantial and meaningful margin among these four coal options and, therefore, is the most cost-effective generation option available with which FPL can both meet future capacity needs in the 2012 - 2015 time period and maintain fuel diversity on its system.

V. Overview of the Approach Used to Analyze the Advanced Technology Units versus Non-Coal-Based Options

Q. Please provide an overview of the analysis approach FPL utilized to evaluate the impacts of adding two advanced technology coal units to FPL's system versus the most likely non-coal options, combined cycle units.

A. The analysis approach FPL utilized can be summarized as follows. First, as explained above, FPL determined that advanced technology coal was the best, most cost-effective option to both meet future capacity needs and maintain system fuel diversity. FPL next developed one resource plan that includes the two advanced technology coal units, the Fuel Diverse Resource Plan with Coal (Plan with Coal). In this resource plan, FPL assumed that the two advanced technology coal units would be added, one by June 2013 and one by June 2014. FPL then developed an alternate resource plan that does not include any coal unit additions, the Resource Plan without Coal (Plan without Coal). Both resource plans included specific units at specific sites for the earlier years and utilized generic unsited "filler" units for the later years. These two resource plans are discussed in more detail later in my testimony. Finally, economic and fuel diversity analyses were then carried out to compare the alternate Plan without Coal to the Plan with Coal.

Q. You mentioned above that "resource plans" were used in the analyses. Why is it appropriate to perform the economic and fuel diversity analyses based on multi-year resource plans?

A. It is not only appropriate to do this, but also necessary if one is to capture and fairly compare all of the economic and fuel diversity impacts of the various capacity options included in the two resource plans designed to address FPL's capacity needs for a specific time period (in this case, 2012-on) will have on FPL's system.

For example, assume we are comparing Option A and Option B. Option A offers 500 MW of capacity and has a heat rate of 7,000 Btu/kwh while Option B has a 9,000 Btu/kwh heat rate, but offers 600 MW of capacity. Evaluating these options from a resource plan perspective allows one to capture the economic impacts of both the heat rate and capacity 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 Option B will. This results in greater production cost savings for Option A. However, Option B's greater capacity means that it is better able to defer the need for future capacity additions. Therefore, Option B will get greater capacity avoidance benefits.

Only by taking a multi-year resource plan approach to the analysis can factors such as these be captured and effectively compared. In the economic analysis, the resource plans created addressed impacts to the FPL system through the year 2054.

Q. Why are "filler" units needed in a resource plan analysis?

A. The two resource plans that FPL developed for use in the analyses each contained various unit additions to address FPL's capacity needs starting in 2012. Specific unit types, sites for the units, and/or purchases were assumed for the 2012 - 2016 time period as will be discussed later in my testimony. The generic "filler" units are needed in a multi-year resource plan analysis as a proxy resource added to meet FPL's capacity needs in later years. In these analyses, filler units were generally used for 2017 – on (i.e., after the 2012 - 2016 options have been added). In this way the two resource plans being compared both meet FPL's reliability criteria for each year in the analysis period, ensuring both that the resource plans are comparable in regard to meeting the 20% reserve margin criterion and that the results of the evaluation of those plans are meaningful.

Q. How were the economic analyses performed?

A. The economic analyses were carried out using FPL's "integrated model." This model primarily consists of a Fixed Cost Spreadsheet and the P-MArea production costing model from P-Plus. The Fixed Cost Spreadsheet model captures all of the fixed costs (capital, fixed O&M, capital replacement, capacity payments for purchases, firm gas transportation, etc.) associated with the two resource plans. The P-MArea model captures variable costs (such as fuel and variable O&M) and projects the annual emission levels associated with the resource plans, plus incorporating the effects of system transmission transfer limits on the dispatch of generating units.

Additional spreadsheets are also used to develop two additional costs for each resource plan. First, the annual emission levels projected in P-MArea are downloaded to a spreadsheet and annual costs for these emissions are calculated. Second, costs for transmission system losses associated with each resource plan are also developed using two spreadsheets, one for peak hour losses and one for annual losses.

This integrated model approach was used in FPL's last Request for Proposal (RFP) evaluation work after FPL's EGEAS model was used to create the various resource plans that resulted from the proposals received in response to the RFP. The EGEAS model was not needed in the current economic analyses because the resource plans to be compared were easily identifiable.

Q. What were the bases of comparison for the economic and fuel diversity analyses of the two resource plans?

A. In regard to the economic analyses, the basis of comparison was the CPVRR of the two plans over the life of the coal units (i.e., 40 years from their respective in-service dates) using a number of combinations (or scenarios) of forecasted fuel costs and environmental compliance costs.

In regard to the fuel diversity analyses, the basis of comparison was annual system energy by fuel type for the two resource plans; i.e., a system fuel diversity comparison, for the 2012 through 2016 time frame for the same fuel cost and environmental compliance cost scenarios. This 5-year time frame was chosen because it addresses the time period for both resource plans before filler units are added.

Q. Why did FPL utilize more than one fuel cost forecast and more than one environmental compliance cost forecast in its analyses?

A. In order to address the potential impacts of uncertainty in both future fuel costs and environmental compliance costs on generating unit options – advanced technology coal and combined cycle (CC) units - that use different types of fuel, namely coal and natural gas, and which have different emission profiles, 4 different fuel cost forecasts and 4 different environmental compliance cost forecasts were used in the analyses. These 4 fuel cost forecasts and 4 environmental compliance cost forecasts were combined to allow FPL's analyses to address 16 different scenarios of forecasted fuel costs and environmental compliance costs.

The specific fuel cost forecasts are discussed in detail in Mr. Yupp's and Mr. Schwartz's testimonies and the specific environmental compliance cost forecasts are discussed in detail in Mr. Kosky's testimony.

VI. The Two Resource Plans Utilized in the Analyses

Q. Please describe the rationale for utilizing the two resource plans in the analyses.

A. FPL selected advanced technology coal units at the FGPP site as the best choice to meet future capacity needs and maintain fuel diversity in FPL's system. For analysis purposes, specific in-service dates are required and FPL analyses assume that the two coal units will come in-service in June 2013 and June 2014, respectively. However, in order to fully evaluate that selection, FPL needed to develop a long-term resource plan that could be used to analyze the long-term system impacts of the addition of the advanced technology coal units. This is the Plan with Coal. In addition, FPL needed to develop an alternative resource plan that did not include coal unit additions that could be used in comparative analyses with the coal-based resource plan. This is the alternate Plan without Coal.

In developing these resource plans, FPL had several criteria. First, each resource plan chosen must meet FPL's system reliability criteria for all years, especially the reliability criterion that currently drives FPL's resource needs, the 20% Summer reserve margin criterion. This ensures that the resource plans will be both meaningful and comparable in regard to system reliability. Second, the cost and performance assumptions (heat rate, availability, etc.) for the generating units that are included in each resource plan should be current assumptions of comparable confidence levels. Third, the resource plans should focus as much as possible on the assumed in-service or decision years in question, 2013 and 2014 and the immediately surrounding years, and should seek to minimize as much as possible influencing the cost and other system impact differences between resource plans that could be caused by the addition of units and/or purchases in other years.

In regard to meeting the first criterion listed above, the 20% reserve margin criterion, the following discussion provides an example, using the Plan with Coal, of how that criterion was met for the two resource plans. First, Document No. SRS-4 presents a revised projection of FPL's capacity needs assuming that the two advanced technology coal units are added, one in June 2013 and one in June 2014. By comparing this document with Document No. SRS-1, it is clear that the capacity need for 2012 is the same, 777 MW. The addition of the 2013 advanced technology coal unit with a Summer capacity rating of 980 MW reduces the 2013 need from 1,194 MW to 214 MW. The addition of the 2014 advanced technology coal unit, also with a Summer capacity rating of 980 MW, fully meets the 2014 capacity need. The addition of these two units also reduces the 2015 capacity need by half; i.e., from the incremental need of (2,283 MW for 2015 – 1,644 MW for 2014 =) 639 MW for 2015 presented in Document No. SRS-1 to 323 MW shown in Document No. SRS-4. In order to meet the remaining capacity needs in 2012 and 2013, FPL has assumed for the purpose of these analyses that a short-term purchase(s) of 800 MW for 2012, and 200 MW for 2013, would be made. It was assumed that each purchase would be made for 5 months, May through September, of each year.

The two resource plans are presented in Document No. SRS-5. Both resource plans meet all of the criteria discussed above.

Q. Does the resource plan that includes coal generation, the Plan with Coal, represent FPL's definitive long-term resource plan?

A. No. FPL believes that the advanced technology coal units included in the Plan with Coal represent the best choice for meeting FPL's capacity needs and for maintaining fuel diversity in FPL's system. These units are the best options to add by 2013 and 2014.

The short-term purchases for 2012 and 2013, and the remaining generating units included in the Plan with Coal for the years following 2014, are reasonable assumptions for meeting system capacity need requirements based on the objective of maintaining system fuel diversity. However, because FPL is not at this time making definitive selections for 2012, for the relatively small additional capacity need in 2013, or for the years beyond 2014, these other capacity additions included in the Plan with Coal would be re-evaluated in the future using updated information when it is necessary to make those resource decisions. Thus FPL believes that the Plan with Coal includes the best generation options to add by 2013 and 2014, and includes reasonable and representative capacity additions for all years, but that these other capacity additions could change in the future due to re-evaluation and/or evolving factors.

Q. Does the alternative resource plan, the Plan without Coal, represent FPL's definitive long-term resource plan that includes no coal?

A. No. The generating units included in the alternative resource plan, the Plan without Coal, would be reasonable choices for meeting system capacity need requirements except for the fact that, as stated in Mr. Silva's testimony, these units would not maintain system fuel diversity. In addition, FPL would not have to make a final decision on gas-fired generation for a 2012 in-service date until 2008 when updated information would be available. For these reasons, although this alternate resource plan is well-suited for use as an alternative, non-coal-based resource plan by which the Plan with Coal can be compared, it is not a definitive long-term resource plan for FPL.

Q. In developing the two resource plans, what assumptions were made in regard to the near-term, 2012 - 2016, unit additions?

A. In developing the two resource plans presented in Document No. SRS-5, several assumptions were made regarding the capacity additions for 2012 - 2016 time period. First, it was assumed for analysis purposes that all new unit additions in both resource plans would have a June 1 in-service date for the respective year in which the capacity addition is needed to meet the reserve margin requirement. For example, the first advanced technology coal unit would be added to FPL's system on June 1, 2013 with the second advanced technology coal unit added in June 1, 2014. Second, the FGPP site and a site at/near the West County Energy Center (referred to in the analyses as the South Florida site) would be the most likely sites for the next several FPL generating unit additions. Third, it was assumed that the FGPP site would be able to accommodate two large generating units, either coal-based or gas-fired, and that the South Florida site would be able to accommodate one large gas-fired generating unit. Fourth, it was assumed that the first gas-fired unit addition would be located at the South Florida site because it would be more economical. Fifth, in regard to the size of the likely gas-fired units (i.e., CC units) included in the plans, FPL's recent analyses indicate that the most cost-effective size for CC units is in the 1,100 to 1,200 MW range. Therefore, it was assumed that the next several CC units added would be in the 1,100 to 1,200 MW range.

In regard to the 2012 - 2016 time period, the Plan with Coal thus includes the previously mentioned short-term purchases of 800 MW (in 2012) and 200 MW (in 2013), plus two advanced technology coal units of 980 MW each, FGPP 1 and 2, that come in-service in 2013 and 2014, respectively. A 1,219 MW CC unit is assumed to be added at the South Florida site in 2015 to meet the 2015 need. This CC unit addition also satisfies the 2016 capacity need.

The Plan without Coal first addresses the 2012 capacity need by adding a 1,219 MW CC unit at the South Florida site in 2012. Because the cumulative capacity need for 2012 and 2013 is 1,194 MW as shown in Document No. SRS-1, this 1,219 MW unit also meets FPL's 2013 capacity need. FPL's remaining capacity needs from 2014 through 2016 are addressed in the Plan without Coal by a pair of 1,119 MW CC units sited at FGPP, one in 2014 and one in 2016.

Q. In developing the two resource plans, what assumptions were made in regard to 2017 - on unit additions?

A. Several assumptions were also made regarding the 2017 – on time period unit additions for the two resource plans. First, each plan assumes that one nuclear unit is added in 2018 and another is added in 2019. This assumption reflects FPL's interest in addressing system fuel diversity in the future with new nuclear capacity additions if such additions prove feasible. These new nuclear unit additions are assumed, for planning purposes, to be sited in Southeast Florida. Second, the remainder of FPL's capacity needs for 2017 and for 2020-on, are assumed to be met by the requisite number of unsited 2x1 CC filler units to meet FPL's system reserve margin requirements. While the timing of these filler units varies slightly between the two resource plans, the number of filler units that is added from 2020-on is identical in each plan.

VII. Fuel Cost and Environmental Compliance Cost Forecasts and Scenarios Used in the Analyses

Q. Please discuss the use of different fuel cost forecasts in the analyses.

A. When comparing generating technologies that burn different fuels, i.e., coal units versus natural gas units, it is appropriate that different fuel cost forecasts be utilized in order to determine the relative economics between the two technologies. In this way the analyses can address the uncertainty that exists regarding future fuel costs, particularly in regard to the future cost differential between natural gas and coal.

Although there are virtually an inexhaustible number of possible future fuel cost outcomes, a small number of forecasts that effectively reflect a reasonable range of future fuel costs are sufficient to conduct a meaningful economic analysis. Consequently, 4 different fuel cost forecasts that reflect a reasonable range of future fuel costs were developed and used in these analyses. These 4 fuel cost forecasts, referred to as Fuel Cost Forecast 1 through Fuel Cost Forecast 4, are summarized in Document No. SRS-6. Mr. Yupp's testimony discusses these forecasts in more detail, including an explanation of how the fuel cost forecasts were developed and why they effectively reflect a reasonable range of future fuel costs.

Q. **Please discuss the use of different environmental compliance cost forecasts in the analyses.**

A. Just as there is uncertainty in regard to the future cost of fuels, there is uncertainty in regard to the future environmental regulations and the costs of complying with those regulations. When comparing generating technologies that burn different fuels and have different emission profiles, such as is the case with coal and natural gas units, the future environmental regulations will determine how the differences in the emission profiles of the generating technologies will affect the relative cost of the technologies. Therefore, FPL found it appropriate to conduct its analyses using different environmental compliance cost forecasts to address the uncertainty that exists regarding future environmental regulations and the costs of complying with those regulations.

As is the case with future fuel costs, there are also a large number of future environmental cost outcomes. However, a small number of forecasts that effectively reflect a reasonable range of future environmental compliance costs are sufficient to conduct a meaningful economic analysis. Therefore, 4 different environmental compliance cost forecasts that reflect a reasonable range of future environmental compliance costs were developed and used in these analyses. These 4 environmental compliance cost forecasts, referred to as Environmental Compliance Cost Forecast A through Environmental Compliance Cost Forecast D, are summarized in Document No. SRS-7. Mr. Kosky's testimony discusses these forecasts in more detail, including an explanation of how the environmental compliance cost forecasts were developed and why they effectively reflect a reasonable range of future environmental compliance costs.

Q. How did FPL make use of the 4 fuel cost forecasts and 4 environmental compliance cost forecasts in its analyses?

A. FPL combined each of the 4 fuel cost forecasts with each of the 4 environmental compliance cost forecasts to develop 16 scenarios of forecasted fuel costs and environmental compliance costs. Each of these 16 scenarios was then utilized separately in both the economic and fuel diversity analyses of the two resource plans.

Because the fuel cost forecasts are designated as 1 through 4 and the environmental compliance cost forecasts are designated as A through D, the 16 scenarios of fuel costs and environmental compliance costs are designated as Scenario 1A, Scenario 1B, etc. through Scenario 4D.

VIII. Results of the Economic Analyses

Q. You previously indicated that FPL's IRP process was used in these analyses. Was the economic analysis used to compare the two resource plans similar to that used in FPL's last several determination of need filings?

A. Yes. The approach used in this economic analysis work was virtually identical to the approach used in FPL's most recent Need filings (i.e., the filings for the Turkey Point 5 and the West County Energy Center 1 and 2 generating units) with one exception, the current utilization of multiple fuel cost and environmental compliance cost forecasts. The rationale for the use of multiple fuel cost and environmental compliance cost forecasts was discussed in the prior section of this testimony.

The economic analysis approach addresses total system costs for the generating system (including all fixed and non-fixed costs), transmission system costs, upstream gas costs, and cost of capital impacts. In this particular application of the approach, FPL has combined transmission capital costs for both interconnection and integration into a transmission capital cost category.

In addition, there were no upstream gas costs and no cost of capital impact (i.e., no equity adjustment) calculation was needed. The upstream gas cost adder is essentially used to account for the combined effect of one or more gas-fired option that is offered to FPL from an outside party for use in an resource plan (such as when bids are received by FPL in response to a Request for Proposals). Because FPL was assumed to supply all of the gas-fired units in each resource plan and the amount of gas needed by, and timing of, those units was known in advance when creating the resource plans, all gas-related costs were accounted for in the unit cost information and no upstream cost adders were needed.

Likewise, all cost of capital impacts were already accounted for by assuming an incremental 55.8% debt / 44.2% equity investment in each new unit in each resource plan. Therefore, no equity adjustment calculation was needed in these economic analyses.

In order to show that the same cost categories were addressed in these economic analyses as were addressed in FPL's most recent Need filings, Document No. SRS-8 presents the economic evaluation results for the two resource plans for one fuel cost and environmental compliance cost scenario, Scenario 1A, using the same presentation format that FPL used in its most recent Need filings. As discussed above, because the costs for Upstream Gas Pipeline and Net Equity Adjustment are zero for both of the two resource plans, these cost categories are not shown.

In this document, only the costs for the Generation System are presented. These Generation System costs are broken out into two categories, Fixed Costs and Variable Costs, and a list of what costs are included in these two categories is shown on the page.

Q. How were the environmental compliance costs captured in the economic analyses?

A. The environmental compliance costs were captured in the economic analyses through 4 steps. First, for each fuel cost and environmental compliance cost forecast scenario, the production costing analyses carried out with the P-MArea model include a projection of the cost of allowances for each applicable emission category. Using the emission rates for each generation unit in FPL's system, P-MArea incorporates the allowance costs for each emission into the dispatch cost for each generating unit and dispatches the generating units on an economic basis to minimize system production costs.

Second, once the production cost projection was completed, the costs of the allowances included in the production costs were subtracted from the production cost projection. Third, the projected annual system emission levels were extracted from the P-MArea results and compared to a projection of the allowance levels for each emission that are assumed to be granted to FPL. (For purposes of these analyses, FPL assumed that no CO_2 allowances would be granted. This assumption serves to maximize the potential cost of complying with potential CO_2 regulations.) The annual differences between emissions and allowances for each emission type are then calculated.

Finally, for each year in which FPL's allowances are less than the projected amount of emissions for each emission type, the net deficit amount of allowances needed to cover emissions is multiplied by that year's projected allowance cost to derive a compliance cost for that year. Conversely, for each year in which FPL's allowances exceed the projected amount of emissions, the net excess amount of allowances is multiplied by that year's projected allowance cost to derive the value of the excess allowances that could be sold. This value is entered as a negative compliance cost for that year. If the amount of allowances exactly equals the projected emissions for a given year, there is no net deficit or excess allowances for the year and, therefore, a zero compliance cost is entered for that year. The compliance costs – positive, negative, or zero – for each year are then summed over the analysis period and the present value of that sum is calculated. This present value amount is then added to P-MArea's fuel and variable O&M costs to derive the Generation System Variable Costs for that scenario.

Q. What conclusions can be drawn from these results shown in Document No. SRS-8?

A. It is important to remember that the results shown in Document No. SRS-8 provide a comparison of only the Generation System costs for the two resource plans (i.e., the Transmission System costs are not yet included) under only one of the 16 fuel cost. and environmental compliance cost scenarios, Scenario 1A.

Document No. SRS-8 shows that the Plan with Coal is approximately $2,808 million CPVRR less expensive than is the Plan without Coal for Scenario 1A. Although this exact result is valid for only one of the 16 fuel cost and environmental compliance cost scenarios, these values do indicate two cost results that will hold true for all of the analyses to follow involving the remaining 15 scenarios.

The first such result is that the Plan with Coal has higher fixed costs and lower variable costs than does the Plan without Coal. This is expected because the Plan with Coal contains the advanced technology coal units while the Plan without Coal does not contain coal units. Coal units have higher capital costs, but have lower energy costs than combined cycle units so a resource plan containing coal units is expected to have higher fixed costs and lower variable costs than a comparable plan without coal units. The second such result is that the Generation System Fixed Costs for each of the two plans are established solely by the generation capacity additions in that resource plan and will not change as fuel costs and/or environmental compliance costs change. Therefore, the Generation System Fixed Costs shown in this document for the two resource plans will remain unchanged for all 16 fuel cost and environmental compliance cost scenarios while the Generation System Variable Costs will change from one scenario to another.

Q. How did these results change when the Transmission System costs are included?

A. Document No. SRS-9, using the same presentation format as Document No. SRS-8, adds the Transmission System costs to the Generation System costs. The resulting total costs for the two plans for Scenario 1A are also shown. The addition of the Transmission System costs changes the result only slightly with the Plan with Coal being $2,792 million CPVRR less expensive than the Plan without Coal for this scenario.

Similar to Generation System Fixed Costs, Transmission System costs are driven by the units being added, the sites at which those units are added, and the timing of the unit additions; i.e., by the resource plans themselves. These costs are not affected by fuel costs and/or environmental compliance costs. Therefore, the Transmission System costs shown in this document will remain unchanged for all of the 15 remaining fuel cost and environmental compliance cost scenarios because the two resource plans will not change.

In regard to the Transmission System costs presented in Document No. SRS-9, there is relatively little difference in the costs between the two resource plans. This fact, when added to the fact mentioned above that Transmission System costs will remain unchanged for all fuel cost and environmental compliance cost scenarios, results in a conclusion that transmission-related costs are not a deciding factor in the analyses.

Q. Please explain the nature of these Transmission System costs.

A. The transmission capital costs are for new transmission facilities required to connect the sited new plant additions in each resource plan to, and integrate them with, the transmission system. Mr. Sanchez's testimony addresses what those transmission facilities are and Mr. Coto's testimony addresses the physical characteristics, schedule, permitting requirements, and estimated costs associated with those facilities.

In addition, Mr. Sanchez's testimony also discusses, for each resource plan, the calculation of losses for both FPL's system peak hour and annually that were developed. These losses are then assigned costs to first represent the loss of capacity at FPL's system peak hour that will eventually need to be addressed by replacement capacity and then the loss of energy to FPL's system during the year that will need to be met by increased energy delivered by FPL's existing units.

Q. How did FPL develop the costs that were assigned to both the peak hour losses and the annual losses?

A. FPL's approach to assigning costs to these losses is identical to that discussed in Appendix E of FPL's last RFP issued on September 9, 2005. In regard to assigning costs to the peak hour loss, FPL first assumed that replacement capacity in the form of purchased power would be secured to address the peak hour capacity loss. FPL assigned an initial proxy purchase cost of $5/kw-month, with an annual escalation rate of 2%, for that replacement capacity.

In assigning costs to the annual energy losses, FPL first had to convert the peak hour losses (MW) and the average load losses (MW) 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 % 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 6,570 annual hours (to reflect the fact that the units in the resource plans are baseload units) 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 Fuel Cost Forecast 1 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 No. SRS-10 and Document No. SRS-11, respectively, present the calculations of costs for the peak hour capacity losses and annual energy losses for the Plan with Coal relative to the Plan without Coal.

Q. What were the results of the economic analyses in which all 16 of the fuel cost and environmental compliance cost scenarios were included?

A. Document No. SRS-12 presents the total costs for the two resource plans for all 16 of these scenarios. In addition, the total cost differences between the Plan with Coal and the Plan without Coal are also shown. The total cost results shown on this document for Scenario 1A for the two resource plans are the same as the total cost results presented for the two resource plans in Document No. SRS-9.

The total cost results shown on Document No. SRS-12 for the remaining 15 scenarios have not been previously presented. However, by examining Document No. SRS-9 and Document No. SRS-12 and considering that the Generation System Fixed Costs and Transmission System Costs shown on Document No. SRS-9 do not change as the scenarios change, it is clear that all of the cost differences shown on Document No. SRS-12 are due to the Generation System Variable Cost category on Document No. SRS-9; i.e., from changes in the fuel costs and/or environmental compliance costs.

In regard to the column titled Total Cost Difference in Document No. SRS-12, a negative value indicates that the costs for the Plan with Coal are lower than those of the Plan without Coal while a positive value indicates that the costs for the Plan with Coal are higher than those of the Plan without Coal.

Document No. SRS-12 shows that, as expected, neither of the two resource plans emerges as the economic choice under all scenarios of fuel cost forecasts and environmental compliance cost forecasts. Both plans emerged as the most economic choice in approximately half of the 16 scenarios; in 7 scenarios for the Plan with Coal and in 9 scenarios for the Plan without Coal.

Document No. SRS-12 provides a significant amount of cost and cost differential data for the two resource plans (and I'll return to discuss the information contained in this document later). In order to simplify this comparison of costs for the two plans, the cost differentials for the two plans that are shown in Document No. SRS-12 are reorganized and presented again in Document No. SRS-13. The intent is to provide a somewhat more easily understood summary of the Total Cost Difference column results in Document No. SRS-12.

Q. How would you summarize the information for each resource plan that is presented in Document No. SRS-13?

A. First, in regard to the Plan with Coal and the 16 scenarios:

- The Plan with Coal is the most economic plan in all scenarios that included the High coal-gas differential Fuel Cost Forecast 1, regardless of the environmental compliance cost forecast; i.e., in scenarios 1A, 1B, 1C, and 1D.

- It is also the most economic plan in scenarios 2A and 2B that include the Shocked coal-gas differential Fuel Cost Forecast 2 and the two lowest environmental compliance cost forecasts (A and B).
- The Plan with Coal is the most economic plan in scenario 3A which includes the Medium coal-gas differential Fuel Cost Forecast 3 and the lowest environmental compliance cost forecast (A).

Second, in regard to the Plan without Coal and the 16 scenarios:

- The Plan without Coal is the most economic plan in all scenarios that included the Low coal-gas differential Fuel Cost Forecast 4, regardless of the environmental compliance cost forecast; i.e., in scenarios 4A, 4B, 4C, and 4D.
- The Plan without Coal is also the most economic plan in scenarios 3B, 3C, and 3D that include the Medium coal-gas differential Fuel Cost Forecast 3 and the three highest environmental compliance cost forecasts (B, C, and D).
- The Plan without Coal is the most economic plan in scenarios 2C and 2D that include the Shocked coal-gas differential Fuel Cost Forecast 2 and the two highest environmental compliance cost forecasts (C and D).

Q. What conclusions did FPL draw from the economic analysis results?

A. As expected, no one plan emerged as the economic choice under all fuel cost and environmental compliance cost forecast scenarios. The Plan with Coal emerged as the economic choice in 7 of the 16 scenarios.

More specifically, the Plan with Coal emerges as the economic choice under all 4 scenarios that include the High coal-gas differential fuel cost forecast regardless of the environmental compliance cost forecast. Conversely, the Plan without Coal emerges as the economic choice under all 4 scenarios that include the Low coal-gas differential fuel cost forecast. As for the remaining 8 scenarios that include either the Shocked or Medium coal-gas differential fuel cost forecasts, each plan emerges as the economic choice in two of the four scenarios that include the Shocked fuel cost forecast while the Plan without Coal generally emerges as the economic choice with the Medium coal-gas differential fuel cost forecasts.

Another important conclusion can be drawn from examination of the Total Cost column in Document No. SRS-12. In those scenarios that include the Low coal-gas differential fuel cost forecasts in which the Plan with Coal was not the economic choice, the total system costs for either plan are significantly lower than the total costs for scenarios that include either the High or Shocked coal-gas differential fuel cost forecasts. The same is true to a lesser extent for the total costs in those scenarios that include the Medium coal-gas differential fuel cost forecasts compared to the total costs for scenarios that include either the High or Shocked coal-gas differential fuel cost forecasts.

These scenarios with lower total costs for both plans are primarily driven by lower natural gas price projections. In these cases, because FPL will have very significant amounts of natural gas generation even after FGPP is added, FPL's customers will enjoy the benefits of lower natural gas costs after FGPP is added to FPL's system.

This point is illustrated by the fact that the cost differential between the two resource plans for Scenario 4D, $4,037 million CPVRR, is much smaller than the projected cost change in the cost of the Plan without Coal under two scenarios that differ only by the projected fuel cost. This can be seen by examining the total costs for the Plan without Coal for scenario 1D ($182,917 million CPVRR) and for scenario 4D ($106,154 million CPVRR). In this example, this projected decrease in total costs of approximately $77,000 million, or $77 billion CPVRR is driven solely by the projected lower system fuel costs in Scenario 4D, particularly lower natural gas costs. Of this potential total cost savings to FPL's customers of $77 billion CPVRR that would occur if the Plan without Coal had been adopted, approximately $73 billion CPVRR cost savings will still be realized with the implementation of the Plan with Coal.

In other words, the Plan with Coal acts as a hedge or insurance against higher natural gas costs.

Q. Do these economic analysis results capture all comparative aspects between the two resource plans for which costs could be assigned?

A. No. There is one comparative aspect of the two resource plans that has not been addressed in the economic analyses. This aspect involves system reliability in the event of a significant fuel supply disruption.

As previously discussed, the two plans are comparable in regard to meeting FPL's reserve margin criterion. However, the two plans are not comparable in regard to their contribution to system reliability in event of a significant fuel supply disruption. The advanced technology coal units at the FGPP site in the Plan with Coal are designed to accommodate a 60-day supply of fuel on-site. In comparison, the combined cycle unit additions in 2012 - 2016 in the Plan without Coal contain on-site backup fuel (i.e., oil) capability of only several days. Consequently, the Plan with Coal, due to the inclusion of the two advanced technology coal units at FGPP, has a significant advantage in regard to system reliability in the event of a significant fuel supply disruption.

In its economic analyses, FPL chose not to attempt to quantify this advantage of the Plan with Coal because the quantification would be dependent upon a number of subjective assumptions including: the likelihood of such a fuel supply disruption occurring, the duration of the disruption, in which year(s) the disruption might occur, etc. Therefore, this real advantage of the FGPP advanced technology coal units is not addressed in the economic analyses.

Q. Has FPL developed cost estimates for providing a comparable level of system on-site fuel storage for the Plan without Coal?

A. Yes. These costs are estimated to be approximately $1.4 to $1.5 billion CPVRR. Mr. Yupp's testimony addresses these estimated costs.

Q. Has FPL calculated the non-fuel costs for the first 12 months of operation for FGPP 1 and 2?

A. Yes. These costs are presented in Document No. SRS-14. The costs presented in Document No. SRS-14 of $708.5 million for FGPP 1 and $469.0 million for FGPP 2 assume a June 1, 2013 in-service date for FGPP 1 and a June 1, 2014 in-service date for FGPP 2. The costs are also based on the in-service costs and financial assumptions used in the economic analyses discussed above. As discussed in the testimony of Mr. Yeager, the actual in-service costs are subject to change for a variety of reasons. If the in-service costs were to change from those assumed in these analyses, the values projected in Document No. SRS-14 would also change.

IX. Results of the Fuel Diversity Analyses

Q. How were the effects of the two plans on FPL's system fuel diversity evaluated?

A. The effects of the two resource plans on FPL's system fuel diversity were evaluated by projecting the annual percentage of system energy that is supplied by each fuel type - coal/petroleum coke, natural gas, oil, nuclear, and other (primarily purchases such as from waste-to-energy facilities) - for both resource plans for the 2012 - 2016 time period; i.e., a system fuel mix projection. This 5-year time period addresses the years before filler units are added to the resource plans.

Generation unit dispatch is affected by the types of generating units available, the fuels they use, and the relative fuel costs and/or environmental compliance costs. Because unit dispatch determines the relative amount of energy that is supplied by each unit, and consequently by each fuel type, the system fuel mix is also affected by the types of generating units available, the fuels they use, and the relative fuel costs and/or environmental compliance costs. Consequently, the fuel diversity results will be presented for each resource plan for two scenarios, Scenarios 1A and 4D, selected to represent the entire range of fuel cost and environmental compliance cost forecasts.

Q. What were the differences in the FPL system fuel mix between the two resource plans?

A. Document No. SRS-15 presents the annual projection for 2012 - 2016 of the percentage of energy produced by coal/petroleum coke, natural gas, oil, nuclear, and other for the two resource plans for the two scenarios. The document also presents the annual differences in these percentages for each fuel type between the Plan with Coal and the Plan without Coal for the two scenarios for the same time period.

As shown in Document No. SRS-15, the Plan with Coal holds a significant advantage in regard to fuel diversity compared to the Plan without Coal. There is little difference between the two plans in regard to the percent of FPL's fuel mix that is supplied by oil, nuclear, or other, but significant differences exist for coal/petroleum coke (coal) and natural gas. When looking at the results for Scenario 1A for the year 2016, it is projected that the Plan with Coal will result in FPL's system supplying approximately 18% of its energy with coal and 60% with natural gas. By comparison, it is projected that the Plan without Coal will result in FPL's system supplying only 7% of its energy with coal and 71% with natural gas. Thus the Plan with Coal is projected to result in a 10-to-11% increase in the contribution from coal, and a corresponding 10-to-11% decrease in the contribution from natural gas, in 2016. A similar change in the percentage contribution from these two fuels is also shown for 2015, another year in which both advanced technology coal units are in-service for a full year.

For Scenario 4D, the contribution from coal is also projected to increase by approximately 10%, while the contribution from natural gas is projected to decrease by approximately 10%, for the Plan with Coal.

Therefore, the Plan with Coal is projected to have a significant fuel diversity advantage over the Plan without Coal, resulting in the FPL system being 10-to-11% more reliant on coal, and 10-to-11% less dependent on natural gas.

X. Adverse Consequences of Not Approving FGPP 1 and 2

Q. Would there be adverse consequences if a Need Determination for FGPP 1 and 2 was not approved?

A. Yes. If FPL's request for a Need Determination for FGPP 1 and 2 is not approved, there would be a significant negative impact in regard to maintaining fuel diversity in FPL's system.

Q. Please discuss the negative impact to FPL's system in regard to maintaining fuel diversity if a Need Determination for FGPP 1 and 2 is not approved.

A. As evidenced by the fuel diversity results presented in Document No. SRS-15 and discussed above, the FPL system is projected to be 10-to-11% more dependent on natural gas, and 10-to-11% less reliant on coal, if the FGPP 1 and 2 units included in the Plan with Coal are not approved.

Therefore, if FGPP 1 and 2 advanced technology coal units are not added by 2013 and 2014 as projected in the Plan with Coal, FPL's system will be significantly more dependent upon natural gas. Such an occurrence would represent a significant reduction in system fuel diversity, thus increasing the exposure of FPL's customers to greater fuel price volatility and resulting in a less reliable system.

Inherent in this discussion and in the analysis results is the assumption that, if a Need Determination for FGPP 1 and 2 is not approved, it would take an extended period of time before other coal-based capacity could be added to FPL's system. It would take a significant amount of time for FPL to be able to propose new coal-based capacity.

A consequence of FGPP 1 and 2 not receiving Need Determination approval in this docket is that the window of opportunity for bringing new coal-based capacity into FPL's system by 2013 will likely have passed. FPL would then have to seek other, non-coal-based new capacity options for meeting the 2013 capacity needs. Such capacity would likely come from new gas-fired options. At best, the earliest new coal-based capacity could be considered for additions to the FPL system would be 2014.

However, the time required for FPL to be able to add other coal-based capacity may be significantly longer than one year. Depending upon the reasons why these advanced technology coal FGPP units were not granted a Need Determination, it may take an extended time to effectively address those reasons. It is also unknown whether FPL would be granted a waiver of the Commission's Bid Rule RFP requirement in an effort to expedite a future coal-based addition. An RFP requirement would add at least a half-year to the timetable. These uncertainties point out that the time required to bring coal-based generation into FPL's system, if a Need Determination for FGPP 1 and 2 is not approved, might be significantly longer than one year.

XI. Conclusions and Testimony Summary

Q. Would you please explain the conclusions you draw from the analyses previously discussed?

A. Yes. I draw the following 4 conclusions from these analyses:

1) The analyses of 4 coal technologies demonstrated that the ultra-supercritical pulverized coal technology option is the most economical coal option with which FPL could address the dual objectives of meeting future capacity needs and maintaining system fuel diversity. Consequently, FPL's selection of this option for its FGPP 1 and 2 units is the correct selection.

2) An economic comparison of a Plan with Coal (that included FGPP 1 and 2) versus a Plan without Coal for 16 scenarios of fuel costs and environmental compliance costs showed that neither resource plan had a distinct advantage throughout the range of scenarios. Each resource plan was the economic choice in approximately half of the scenarios, 7 for the Plan with Coal and 9 for the Plan without Coal.

3) However, when comparing the CPVRR total cost differential between the two resource plans for those scenarios in which the Plan without Coal was the economic choice, the total cost disadvantage of the Plan with Coal versus the Plan without Coal, a maximum of approximately $4 billion CPVRR, is significantly lower than was the total cost differential for the Plan without Coal when comparing total costs for the High and Low fuel cost forecasts for the same environmental compliance cost forecast, a difference of approximately $77 billion CPVRR. Therefore, FPL's customers will experience significant total cost savings if actual fuel costs more closely match Fuel Cost Forecast 4 (Low coal-gas differential) than Fuel Cost Forecast 1 (High coal-gas differential). These savings of approximately $77 billion CPVRR would only be reduced by a comparatively small amount, $4 billion or less CPVRR, if the Plan with Coal had been selected, still resulting in savings of approximately $73 billion CPVRR. Therefore, the Plan with Coal can be viewed as a reasonable

cost hedge or insurance against high fuel costs, primarily high natural gas costs.

4) The Plan with Coal has a significant advantage in regard to system fuel diversity. The projected system fuel mix values for 2015 and 2016, the first years that include a full year's operation of both FPGG units, show that the Plan with Coal would increase the FPL's system's use of coal by 10-to-11%, while reducing its dependence on natural gas by 10-to-11%, compared to the Plan without Coal.

Q. Please summarize your testimony.

A. FPL's 2006 resource planning work determined that FPL has future capacity needs starting in 2012 through 2015 that total 2,283 MW of incremental capacity (power plant construction and/or new purchases) or 1,904 MW at the generator of additional cost-effective DSM. All DSM that is known to be cost-effective has already been reflected in FPL's 2006 resource planning work. Therefore, in order to meet FPL's Summer reserve margin criterion of 20% through 2015, FPL needs 2,283 MW of new capacity (power plant construction and/or purchase).

FPL also determined that a key objective during this resource planning cycle was to select a capacity option that would maintain FPL's system fuel diversity. Because FPL's future capacity needs begin starting in 2012, coal technology options were the options of choice both to address these relatively near-term future capacity needs and to maintain system fuel diversity. FPL subsequently analyzed 4 coal technologies and selected ultra-supercritical pulverized coal technology as the best, most cost-effective choice to meet its capacity needs and maintain system fuel diversity.

FPL developed a Plan with Coal that included the two FGPP advanced technology coal units, and an alternate Plan without Coal, in order to determine the economic and fuel diversity impacts of adding the advanced technology coal units. FPL's analyses compared the Plan with Coal to the alternate Plan without Coal under 16 scenarios of forecasted fuel costs and environmental compliance costs.

The economic analyses showed that from a total CPVRR cost perspective each resource plan emerged as the lower cost plan in approximately half of the scenarios, 7 for the Plan with Coal and 9 for the Plan without Coal. However, when comparing the total CPVRR cost disadvantage of the Plan with Coal in the scenarios in which it was not the lower cost plan, this disadvantage was significantly less than the total cost difference for the Plan without Coal between the High and Low fuel cost forecasts for the same environmental compliance cost forecast. Therefore, the additional cost of the Plan with Coal can be seen as a reasonable cost to pay for a hedge or insurance against high fuel costs, especially high natural gas costs.

The fuel diversity analyses showed that the Plan with Coal has a significant advantage in regard to system fuel diversity. This plan results in a projected FPL system fuel mix that would be 10-to-11% more reliant on coal, and 10-to-11% less dependent on natural gas, compared to the Plan without Coal.

Q. Does this conclude your testimony?

A. Yes.

Projection of FPL's 2007 - 2015 Capacity Needs
(without New Resource Additions)

Summer

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
August of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Summer DSM Forecast * (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Reserve Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2007	22,123	2,993	25,116	22,259	1,768	20,491	4,625	22.6%	(527)
2008	22,150	2,993	25,143	22,770	1,908	20,862	4,281	20.5%	(109)
2009	23,370	2,511	25,881	23,435	2,034	21,401	4,480	20.9%	(200)
2010	24,589	2,107	26,696	24,003	2,146	21,857	4,839	22.1%	(468)
2011	24,589	2,062	26,651	24,612	2,264	22,348	4,303	19.3%	**167**
2012	24,589	1,906	26,495	25,115	2,388	22,727	3,768	16.6%	**777**
2013	24,589	1,906	26,495	25,590	2,516	23,074	3,421	14.8%	**1,194**
2014	24,589	1,906	26,495	26,100	2,651	23,449	3,046	13.0%	**1,644**
2015	24,589	1,906	26,495	26,772	2,790	23,982	2,513	10.5%	**2,283**

Winter

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
January of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Winter DSM Forecast * (MW)	Forecast of Firm Peak (MW)	Forecast of Winter Reserves (MW)	Forecast of Winter Reserve Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2007	22,294	3,862	26,156	22,247	1,555	20,692	5,464	26.4%	(1,326)
2008	23,503	3,026	26,529	22,627	1,649	20,978	5,551	26.5%	(1,355)
2009	23,531	2,700	26,231	23,115	1,750	21,365	4,866	22.8%	(593)
2010	24,866	2,188	27,054	23,587	1,814	21,773	5,281	24.3%	(926)
2011	26,201	2,095	28,296	24,047	1,883	22,164	6,132	27.7%	(1,699)
2012	26,201	2,095	28,296	24,498	1,954	22,544	5,752	25.5%	(1,243)
2013	26,201	1,915	28,116	24,952	2,028	22,924	5,192	22.6%	(607)
2014	26,201	1,915	28,116	25,416	2,106	23,310	4,806	20.6%	(144)
2015	26,201	1,915	28,116	26,048	2,188	23,860	4,256	17.8%	**516**

* DSM values shown represent cumulative load management and incremental conservation capability.

Additional FPL DSM Above DSM Goals: 2006 - 2015

(Approximate Cumulative Summer MW)

	(1)	(2) = (1) /(1-0.0923)	(3)	(4)	(5) = (3) + (4)
Year	**DSM Goals 2005 - 2015 Summer MW at Meter (1)**	**DSM Goals 2005 - 2015 Summer MW at Generator (2)**	**DSM Goals 2006 - 2015 Summer MW at Generator (3)**	**Additional DSM 2006 - 2015 Summer MW at Generator (4)**	**2006 - 2015 Total Projected Summer MW at Generator (5)**
2005	74.0	82	---	---	---
2006	141.7	156	75	39	114
2007	211.9	233	152	229	381
2008	287.2	316	235	289	524
2009	365.9	403	322	334	656
2010	447.9	493	412	372	784
2011	532.1	586	505	413	918
2012	618.8	682	600	456	1,056
2013	707.9	780	698	501	1,199
2014	801.7	883	802	548	1,350
2015	801.7	883	802	564	1,366

Notes: (1) The Commission-approved DSM Goals address 2005 - 2014 and represent DSM MW at the meter.

(2) The DSM Summer MW at the Generator are approximate values based on a 9.23% line loss factor.

(3) These values represent DSM Goals values from 2006 through 2015 and omit the 2005 Goals values.

(4) The values shown above for 2006 through 2008 were originally presented in FPL's 2006 Ten Year Site Plan in Table III.D.2 on page 62. Those values represented the additional DSM MW contribution through 2008 at the time the Site Plan was filed. The 2009 - on values represent a current projection of additional DSM due to FPSC approval in mid-2006 of modifications to existing FPL DSM programs and of new DSM programs.

(5) The Total Projected Summer MW at Generator values are the sum of the DSM Goals Summer MW at Generator values and the Additional DSM Summer MW values.

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S. Sim, Exhibit No. ___
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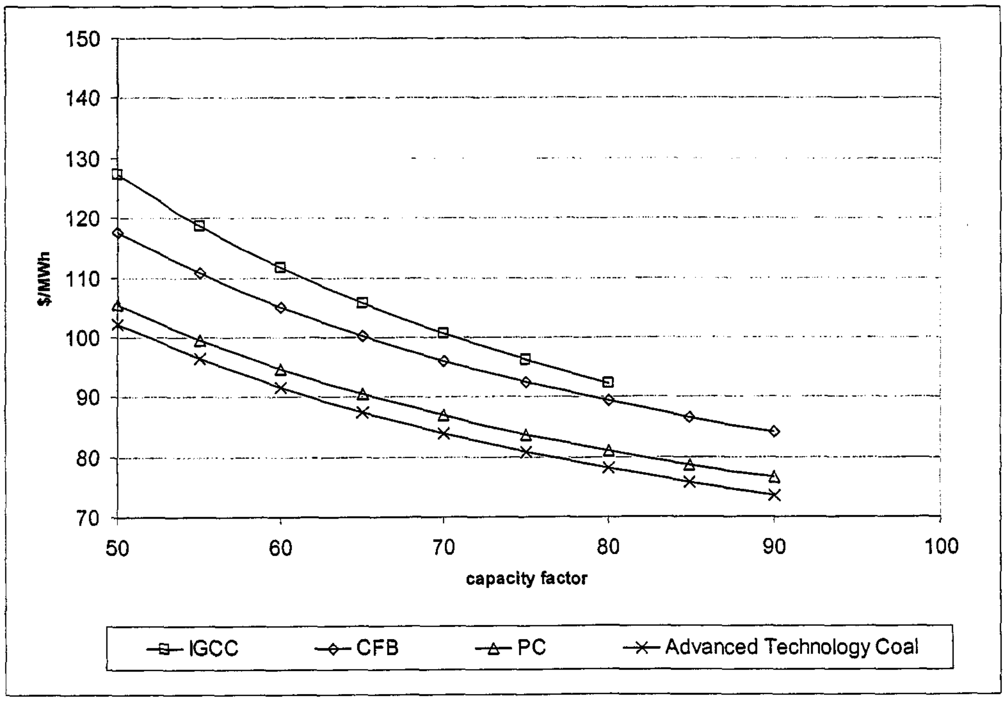
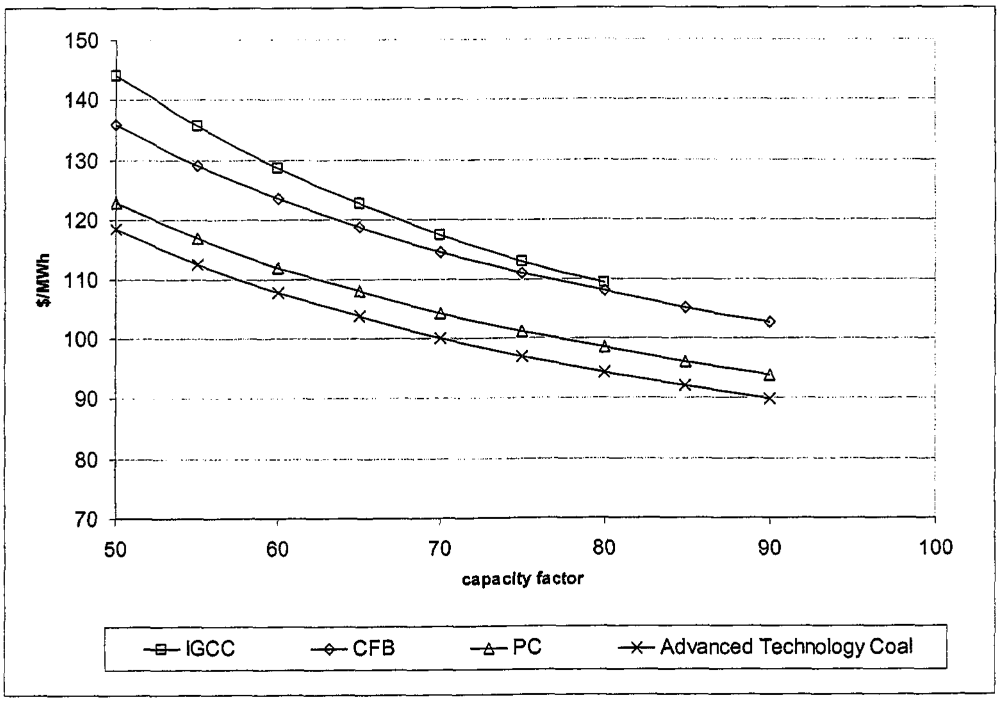
Economic Analyses of Coal
Technologies

Economic Analyses of Coal Technologies : without Allowance Costs



Economic Analyses of Coal Technologies : with Allowance Costs



Projection of FPL's 2007 - 2015 Capacity Needs: With FGPP 1 & 2

Summer

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
August of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Summer DSM Forecast * (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Reserve Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2007	22,123	2,993	25,116	22,259	1,768	20,491	4,625	22.6%	(527)
2008	22,150	2,993	25,143	22,770	1,908	20,862	4,281	20.5%	(109)
2009	23,370	2,511	25,881	23,435	2,034	21,401	4,480	20.9%	(200)
2010	24,589	2,107	26,696	24,003	2,146	21,857	4,839	22.1%	(468)
2011	24,589	2,062	26,651	24,612	2,264	22,348	4,303	19.3%	**167**
2012	24,589	1,906	26,495	25,115	2,388	22,727	3,768	16.6%	**777**
2013	25,569	1,906	27,475	25,590	2,516	23,074	4,401	19.1%	**214**
2014	26,549	1,906	28,455	26,100	2,651	23,449	5,006	21.3%	(316)
2015	26,549	1,906	28,455	26,772	2,790	23,982	4,473	18.7%	**323**

Winter

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
January of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Winter DSM Forecast * (MW)	Forecast of Firm Peak (MW)	Forecast of Winter Reserves (MW)	Forecast of Winter Reserve Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2007	22,294	3,862	26,156	22,247	1,555	20,692	5,464	26.4%	(1,326)
2008	23,503	3,026	26,529	22,627	1,649	20,978	5,551	26.5%	(1,355)
2009	23,531	2,700	26,231	23,115	1,750	21,365	4,866	22.8%	(593)
2010	24,866	2,188	27,054	23,587	1,814	21,773	5,281	24.3%	(926)
2011	26,201	2,095	28,296	24,047	1,883	22,164	6,132	27.7%	(1,699)
2012	26,201	2,095	28,296	24,498	1,954	22,544	5,752	25.5%	(1,243)
2013	26,201	1,915	28,116	24,952	2,028	22,924	5,192	22.6%	(607)
2014	27,191	1,915	29,106	25,416	2,106	23,310	5,796	24.9%	(1,134)
2015	28,181	1,915	30,096	26,048	2,188	23,860	6,236	26.1%	(1,464)

* DSM values shown represent cumulative load management and incremental conservation capability.

The Two Resource Plans Utilized in the Analyses

Plan with Coal	2012	2013	2014	2015	2016	2017	2018	2019	2020 - 2040
- unit(s)/purchase(s) added	Short-term purchase	FGPP 1 & Short-term purchase	FGPP 2	South Florida CC	(none)	2 - 2x1 CC	Nuclear # 1	Nuclear # 2	35 - 2x1 CC
- site	Unknown	Glades & Unknown	Glades	West County vicinity	---	unsited	SE Florida	SE Florida	unsited
- annual MW added	800	980 & 200	980	1,219	0	1,106	1,090	1,090	19,355
- cumulative MW added	800	1,180	2,160	3,379	3,379	4,485	5,575	6,665	26,020
- cumulative sited MW	800	980	1,960	3,179	3,179	---	---	---	---
- Reserve Margin	20.1%	19.9%	21.3%	23.7%	19.6%	21.4%	23.1%	24.7%	(all meet criteria)

Plan without Coal	2012	2013	2014	2015	2016	2017	2018	2019	2020 - 2040
- unit(s)/purchase(s) added	South Florida CC	(none)	1 - 3x1 CC	(none)	1 - 3x1 CC	1 - 2x1 CC	Nuclear # 1	Nuclear # 2	35 - 2x1 CC
- site	West County vicinity	---	Glades	---	Glades	unsited	SE Florida	SE Florida	unsited
- annual MW added	1,219	0	1,119	0	1,119	553	1,090	1,090	19,355
- cumulative MW added	1,219	1,219	2,338	2,338	3,457	4,010	5,100	6,190	25,545
- cumulative sited MW	1,219	1,219	2,338	2,338	3,457	---	---	---	---
- Reserve Margin	21.9%	20.1%	23.0%	20.2%	20.7%	20.3%	22.0%	23.7%	(all meet criteria)

Notes:
- assumes comparable replacement of UPS 930 MW purchase from Georgia for 5 years (2016 - 2020)
- assumes extension of DSM implementation beyond current forecast at 120 MW/year for 2016 - 2020
- assumes no peak load or annual energy growth after 2040

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The Two Resource Plans Utilized in the Analyses

Fuel Cost Forecasts Utilized in the Analyses (1)
($/mmBTU)

	"High" Gas - Coal Cost Differential Forecast 1	"Shock" Gas - Coal Cost Differential Forecast 2	"Medium" Gas - Coal Cost Differential Forecast 3	"Low" Gas - Coal Cost Differential Forecast 4
Coal Mix (40%/40%/20%) (2):				
-2012	$3.38	$2.85	$2.85	$2.60
-2020	$3.99	$3.37	$3.37	$3.07
-2030	$4.95	$4.18	$4.18	$3.80
-2040	$6.16	$5.20	$5.20	$4.73
-2050	$7.71	$6.51	$6.51	$5.93
Fuel Oil (3):				
-2012	$11.65	$12.89	$8.37	$6.80
-2020	$16.54	$11.88	$11.88	$9.65
-2030	$22.01	$15.81	$15.81	$12.85
-2040	$29.24	$21.01	$21.01	$17.07
-2050	$38.80	$27.87	$27.87	$22.65
Natural Gas (4) :				
-2012	$9.21	$11.70	$6.36	$4.15
-2020	$13.93	$9.61	$9.61	$6.27
-2030	$18.77	$12.96	$12.96	$8.45
-2040	$25.23	$17.41	$17.41	$11.36
-2050	$33.82	$23.35	$23.35	$15.23
Gas - Coal Mix Differential:				
-2012	$5.83	$8.85	$3.51	$1.55
-2020	$9.93	$6.24	$6.24	$3.20
-2030	$13.82	$8.78	$8.78	$4.65
-2040	$19.06	$12.21	$12.21	$6.62
-2050	$26.11	$16.84	$16.84	$9.30

Notes:

(1) Delivered fuel cost values used in FPL's analyses are shown for selected years to provide perspective of the range of fuel cost projections used.
(2) Coal mix assumes 40% domestic coal, 40% international coal, and 20% petroleum coke.
(3) Fuel oil cost values represent delivered costs of heavy oil to Turkey Point site.
(4) Natural gas cost projections represent delivered Gulfstream dispatch price from from Mobile Bay only and do not include pipeline demand charges.

Environmental Compliance Cost Forecasts Utilized in the Analyses

	"3 Emissions Cost" Forecast A	"3 Emissions plus Low CO_2 Cost" Forecast B	"3 Emissions plus Medium CO_2 Cost" Forecast C	"3 Emissions plus High CO_2 Cost" Forecast D
SO_2 ($/ton) :				
-2012	$1,635	$1,502	$1,374	$1,343
-2020	$3,309	$3,040	$2,784	$2,717
-2030	$6,619	$5,681	$4,915	$4,064
-2040	$8,269	$7,096	$6,140	$5,077
-2050	$10,329	$8,865	$7,670	$6,342
NO_X ($/ton) :				
-2012	$1,958	$1,927	$2,145	$2,106
-2020	$3,679	$3,900	$4,344	$4,264
-2030	$3,656	$3,082	$1,490	$0
-2040	$4,567	$3,850	$1,861	$0
-2050	$5,705	$4,809	$2,324	$0
CO_2 ($/ton) :				
-2012	$0	$7	$0	$11
-2020	$0	$13	$25	$28
-2030	$0	$17	$49	$66
-2040	$0	$22	$61	$83
-2050	$0	$27	$76	$103
Hg ($/lb) :				
-2012	$29,750	$29,719	$28,879	$28,741
-2020	$56,692	$55,131	$50,212	$49,976
-2030	$137,500	$133,710	$121,769	$121,216
-2040	$171,765	$167,031	$152,115	$151,424
-2050	$214,570	$208,655	$190,022	$189,159

Economic Analysis Results for One Fuel and Environmental Compliance Cost Scenario:
Generation System Costs Only
(millions, CPVRR, 2006$, 2006 - 2054)

Fuel Cost Forecast = **1**

Environmental Compliance Cost Forecast = **A**

	(1)	(2)	(3) = (1) + (2)	(4)	(5)	(6)	(7)	(8) = (3) +(7)	(9)
	Generation System Costs			**Transmission System Costs**					
Resource Plan	**Fixed Costs ***	**Variable Costs ****	**Total Costs**	**Capital Costs**	**Capacity Losses**	**Energy Losses**	**Total Costs**	**Total Costs**	**Difference from Lowest Cost Plan**
Plan 1	19,185	140,185	159,370	0	0	0	0	159,370	0
Plan 2	16,061	146,117	162,178	0	0	0	0	162,178	2,808

* Generation system fixed costs include: capital, capacity payments, fixed O&M, capital replacement, gas pipeline lateral, and fuel inventory costs.

** Generation system variable costs include: variable O&M, plant fuel, FPL system fuel, and environmental compliance costs.

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Economic Analysis Results for One
Fuel and Environmental
Compliance Cost Scenario:
Generation System Costs Only

Economic Analysis Results for One Fuel and Environmental Compliance Cost Scenario:
Generation System and Transmission System Costs
(millions, CPVRR, 2006$, 2006 - 2054)

Fuel Cost Forecast = **1**

Environmental Compliance Cost Forecast = **A**

	Generation System Costs			Transmission System Costs					
	(1)	(2)	(3) = (1) + (2)	(4)	(5)	(6)	(7)	(8) = (3) +(7)	(9)
Resource Plan	**Fixed Costs ***	**Variable Costs ****	**Total Costs**	**Capital Costs**	**Capacity Losses *****	**Energy Losses *****	**Total Costs**	**Total Costs**	**Difference from Lowest Cost Plan**
Plan with Coal	19,185	140,185	159,370	586	(1)	(10)	575	159,945	0
Plan without Coal	16,061	146,117	162,178	559	0	0	559	162,737	2,792

* Generation system fixed costs include: capital, capacity payments, fixed O&M, capital replacement, gas pipeline lateral, and fuel inventory costs.

** Generation system variable costs include: variable O&M, plant fuel, FPL system fuel, and environmental compliance costs.

*** The Transmission System cost of losses, both for capacity and energy, for the Plan with Coal are relative to the Plan without Coal.

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Economic Analysis Results for One
Fuel and Environmental Compliance
Cost Scenario: Generation System and
Transmission System Costs

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S. Sim, Exhibit No. ___
Document No. SRS-10, Page 1 of 1
Calculation of Peak Hour Loss
Cost for the Plan with Coal
Compared to the Plan without Coal

Calculation of Peak Hour Loss Cost for the Plan with Coal Compared to the Plan without Coal

Discount Rate =	0.0882
Purchase Proxy Starting Cost ($/kw) =	$5.00
Annual Escalation Rate for Proxy Purchase =	2%

	(1)	(2)	(3)	(4)	(5)
				= (1)*(3)*12	= (2)*(4)
Year	Proxy Purchase Cost ($/kw-mo)	Discount Factor	Peak Load Loss (MW)	Peak Hour Capacity Loss Cost Nominal ($ 000)	Peak Hour Capacity Loss Cost NPV ($ 000)
2006	$0.00	1.000	0.00	$0	$0
2007	$0.00	0.919	0.00	$0	$0
2008	$0.00	0.844	0.00	$0	$0
2009	$0.00	0.776	0.00	$0	$0
2010	$0.00	0.713	0.00	$0	$0
2011	$0.00	0.655	0.00	$0	$0
2012	$0.00	0.602	0.00	$0	$0
2013	$0.00	0.553	0.00	$0	$0
2014	$5.00	0.509	(14.30)	($858)	($436)
2015	$5.10	0.467	(40.32)	($2,468)	($1,153)
2016	$5.20	0.429	(6.40)	($400)	($172)
2017	$5.31	0.395	(21.70)	($1,382)	($545)
2018	$5.41	0.363	3.30	$214	$78
2019	$5.52	0.333	3.30	$219	$73
2020	$5.63	0.306	3.30	$223	$68
2021	$5.74	0.281	3.30	$227	$64
2022	$5.86	0.259	3.30	$232	$60
2023	$5.98	0.238	3.30	$237	$56
2024	$6.09	0.218	3.30	$241	$53
2025	$6.22	0.201	3.30	$246	$49
2026	$6.34	0.184	3.30	$251	$46
2027	$6.47	0.169	3.30	$256	$43
2028	$6.60	0.156	3.30	$261	$41
2029	$6.73	0.143	3.30	$266	$38
2030	$6.86	0.132	3.30	$272	$36
2031	$7.00	0.121	3.30	$277	$34
2032	$7.14	0.111	3.30	$283	$31
2033	$7.28	0.102	3.30	$288	$29
2034	$7.43	0.094	3.30	$294	$28
2035	$7.58	0.086	3.30	$300	$26
2036	$7.73	0.079	3.30	$306	$24
2037	$7.88	0.073	3.30	$312	$23
2038	$8.04	0.067	3.30	$318	$21
2039	$8.20	0.061	3.30	$325	$20
2040	$8.37	0.056	3.30	$331	$19
2041	$8.53	0.052	3.30	$338	$18
2042	$8.71	0.048	3.30	$345	$16
2043	$8.88	0.044	3.30	$352	$15
2044	$9.06	0.040	3.30	$359	$14
2045	$9.24	0.037	3.30	$366	$14
2046	$9.42	0.034	3.30	$373	$13
2047	$9.61	0.031	3.30	$381	$12
2048	$9.80	0.029	3.30	$388	$11
2049	$10.00	0.026	3.30	$396	$10
2050	$10.20	0.024	3.30	$404	$10
2051	$10.40	0.022	3.30	$412	$9
2052	$10.61	0.020	3.30	$420	$9
2053	$10.82	0.019	3.30	$429	$8
2054	$11.04	0.017	3.30	$437	$8
				NPV Total ($000) =	($1,179)

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S. Sim, Exhibit No. ___
Document No. SRS-11, Page 1 of 1
Calculation of Annual Energy Loss
Cost for the Plan with Coal
Compared to the Plan without Coal

Calculation of Annual Energy Loss Cost for the Plan with Coal Compared to the Plan without Coal

On-Peak Hours =	876	(or 10% of all hours)
Off-Peak Hours =	6,570	
Discount Factor =	0.0882	

	(1)	(2)	(3)	(4)	(5) = (4)*On-Peak Hours	(6) = (1)*(5)/1000	(7)	(8) = (7)*Off-Peak Hours	(9) = (2)*(8)/1000	(10) = (6) + (9)	(11) = (3)*(10)
Year	On-Peak Marginal Energy Cost ($/mwh)	Off-Peak Marginal Energy Cost ($/mwh)	Discount Factor	Peak Load Loss (MW)	On - Peak Hours Annual Energy Loss (MWH)	On - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Average Load Loss (MW)	Off - Peak Hours Annual Energy Loss (MWH)	Off - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost NPV ($ 000)
2006	0	0	1.000	0	0	$0	0	0	$0	$0	$0
2007	$127.50	$104.78	0.919	0	0	$0	0	0	$0	$0	$0
2008	$130.77	$104.82	0.844	0	0	$0	0	0	$0	$0	$0
2009	$115.34	$84.87	0.776	0	0	$0	0	0	$0	$0	$0
2010	$109.00	$79.49	0.713	0.00	0	$0	0.00	0	$0	$0	$0
2011	$98.64	$71.47	0.655	0.00	0	$0	0.00	0	$0	$0	$0
2012	$105.39	$79.31	0.602	(14.30)	(12,527)	($1,320)	6.21	40,800	$3,236	$1,915	$1,153
2013	$108.51	$81.57	0.553	(40.32)	(35,320)	($3,833)	(21.55)	(141,584)	($11,549)	($15,382)	($8,512)
2014	$111.29	$80.70	0.509	(6.40)	(5,606)	($624)	(0.31)	(2,037)	($164)	($788)	($401)
2015	$117.24	$82.13	0.467	(21.70)	(19,009)	($2,229)	11.28	74,110	$6,087	$3,858	$1,803
2016	$125.97	$90.41	0.429	3.30	2,891	$364	(1.47)	(9,658)	($873)	($509)	($219)
2017	$135.17	$96.14	0.395	3.30	2,891	$391	(1.47)	(9,658)	($929)	($538)	($212)
2018	$143.56	$101.28	0.363	3.30	2,891	$415	(1.47)	(9,658)	($978)	($563)	($204)
2019	$151.79	$101.85	0.333	3.30	2,891	$439	(1.47)	(9,658)	($984)	($545)	($182)
2020	$162.40	$110.91	0.306	3.30	2,891	$469	(1.47)	(9,658)	($1,071)	($602)	($184)
2021	$171.13	$121.69	0.281	3.30	2,891	$495	(1.47)	(9,658)	($1,175)	($681)	($192)
2022	$174.99	$120.47	0.259	3.30	2,891	$506	(1.47)	(9,658)	($1,163)	($658)	($170)
2023	$180.15	$121.55	0.238	3.30	2,891	$521	(1.47)	(9,658)	($1,174)	($653)	($155)
2024	$185.79	$124.18	0.218	3.30	2,891	$537	(1.47)	(9,658)	($1,199)	($662)	($145)
2025	$192.32	$128.22	0.201	3.30	2,891	$556	(1.47)	(9,658)	($1,238)	($682)	($137)
2026	$197.05	$131.46	0.184	3.30	2,891	$570	(1.47)	(9,658)	($1,270)	($700)	($129)
2027	$202.10	$133.39	0.169	3.30	2,891	$584	(1.47)	(9,658)	($1,288)	($704)	($119)
2028	$208.04	$137.66	0.156	3.30	2,891	$601	(1.47)	(9,658)	($1,330)	($728)	($113)
2029	$214.63	$141.80	0.143	3.30	2,891	$620	(1.47)	(9,658)	($1,369)	($749)	($107)
2030	$220.99	$145.61	0.132	3.30	2,891	$639	(1.47)	(9,658)	($1,406)	($767)	($101)
2031	$225.38	$149.03	0.121	3.30	2,891	$652	(1.47)	(9,658)	($1,439)	($788)	($95)
2032	$229.19	$152.75	0.111	3.30	2,891	$663	(1.47)	(9,658)	($1,475)	($813)	($90)
2033	$237.83	$158.28	0.102	3.30	2,891	$688	(1.47)	(9,658)	($1,529)	($841)	($86)
2034	$239.84	$161.68	0.094	3.30	2,891	$693	(1.47)	(9,658)	($1,561)	($868)	($81)
2035	$243.30	$166.61	0.086	3.30	2,891	$703	(1.47)	(9,658)	($1,609)	($906)	($78)
2036	$254.22	$172.09	0.079	3.30	2,891	$735	(1.47)	(9,658)	($1,662)	($927)	($73)
2037	$258.31	$177.33	0.073	3.30	2,891	$747	(1.47)	(9,658)	($1,713)	($966)	($70)
2038	$251.38	$182.06	0.067	3.30	2,891	$727	(1.47)	(9,658)	($1,758)	($1,032)	($69)
2039	$251.55	$187.58	0.061	3.30	2,891	$727	(1.47)	(9,658)	($1,812)	($1,084)	($67)
2040	$256.22	$193.34	0.056	3.30	2,891	$741	(1.47)	(9,658)	($1,867)	($1,127)	($64)
2041	$258.88	$199.18	0.052	3.30	2,891	$748	(1.47)	(9,658)	($1,924)	($1,175)	($61)
2042	$261.58	$205.20	0.048	3.30	2,891	$756	(1.47)	(9,658)	($1,982)	($1,226)	($58)
2043	$264.30	$211.40	0.044	3.30	2,891	$764	(1.47)	(9,658)	($2,042)	($1,278)	($56)
2044	$267.05	$217.78	0.040	3.30	2,891	$772	(1.47)	(9,658)	($2,103)	($1,331)	($54)
2045	$269.82	$224.36	0.037	3.30	2,891	$780	(1.47)	(9,658)	($2,167)	($1,387)	($51)
2046	$272.63	$231.14	0.034	3.30	2,891	$788	(1.47)	(9,658)	($2,232)	($1,444)	($49)
2047	$275.47	$238.12	0.031	3.30	2,891	$796	(1.47)	(9,658)	($2,300)	($1,503)	($47)
2048	$278.33	$245.31	0.029	3.30	2,891	$805	(1.47)	(9,658)	($2,369)	($1,565)	($45)
2049	$281.23	$252.72	0.026	3.30	2,891	$813	(1.47)	(9,658)	($2,441)	($1,628)	($43)
2050	$284.15	$260.36	0.024	3.30	2,891	$821	(1.47)	(9,658)	($2,515)	($1,693)	($41)
2051	$287.11	$268.22	0.022	3.30	2,891	$830	(1.47)	(9,658)	($2,590)	($1,761)	($39)
2052	$290.09	$276.33	0.020	3.30	2,891	$839	(1.47)	(9,658)	($2,669)	($1,830)	($37)
2053	$293.11	$284.67	0.019	3.30	2,891	$847	(1.47)	(9,658)	($2,749)	($1,902)	($36)
2054	$296.16	$293.27	0.017	3.30	2,891	$856	(1.47)	(9,658)	($2,832)	($1,976)	($34)
										NPV Total ($000) =	($9,752)

Economic Analysis Results: Total Costs and Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios

(millions, CPVRR, 2006$, 2006 - 2054)

	(1)	(2)	(3)	(4)	(5) = (3) - (4)
Scenario	Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans: Plan with Coal	Total Costs for Plans: Plan without Coal	Total Cost Difference Plan with Coal - Plan without Coal
1A	1	A	159,945	162,737	(2,792)
1B	1	B	167,777	169,822	(2,045)
1C	1	C	176,514	177,640	(1,127)
1D	1	D	182,252	182,917	(666)
2A	2	A	141,840	142,713	(873)
2B	2	B	149,592	149,705	(113)
2C	2	C	158,332	157,528	804
2D	2	D	164,046	162,768	1,278
3A	3	A	118,469	118,689	(219)
3B	3	B	126,258	125,721	537
3C	3	C	134,990	133,524	1,466
3D	3	D	140,745	138,815	1,930
4A	4	A	87,989	86,077	1,912
4B	4	B	95,909	93,239	2,670
4C	4	C	104,508	100,904	3,604
4D	4	D	110,191	106,154	4,037

Note: A negative value in Column (5) indicates that the Plan with Coal is more expensive than than the Plan without Coal. Conversely, a positive value in Column (5) indicates that the Plan with Coal is more expensive than the Plan without Coal.

Plan with Coal Costs Prior to Trans Losses	Plan with Coal Relative Costs for Capacity Losses	Plan with Coal Relative Costs for Energy Losses	Plan with Coal Total Costs
159,956	(1)	(10)	159,945
167,788	(1)	(10)	167,777
176,524	(1)	(10)	176,514
182,263	(1)	(10)	182,252
141,851	(1)	(10)	141,840
149,603	(1)	(10)	149,592
158,343	(1)	(10)	158,332
164,057	(1)	(10)	164,046
118,480	(1)	(10)	118,469
126,268	(1)	(10)	126,258
135,001	(1)	(10)	134,990
140,756	(1)	(10)	140,745
88,000	(1)	(10)	87,989
95,920	(1)	(10)	95,909
104,519	(1)	(10)	104,508
110,202	(1)	(10)	110,191

Economic Analysis Results: the Plan with Coal vs the Plan without Coal Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios

Total Cost Differentials *
(millions, CPVRR, 2006$, 2006 - 2054)

		Fuel Cost Forecasts			
		1 High Differential	2 Shocked Differential	3 Medium Differential	4 Low Differential
Environmental	A	(2,792)	(873)	(219)	1,912
Compliance Cost	B	(2,045)	(113)	537	2,670
Forecasts	C	(1,127)	804	1,466	3,604
	D	(666)	1,278	1,930	4,037

* A negative value indicates that the Plan with Coal is less expensive than the Plan without Coal. Conversely, a positive value indicates that Plan with Coal is more expensive than the Plan without Coal.

Non-Fuel Cost Projections for the First 12 Months of Operation for FGPP 1 & 2

Assumptions: (all cost values are for the full year and are in Nomial $, millions)

	FGPP 1	FGPP 2
In-Service Date =	June 1, 2013	June 1, 2014
1st Year Capital Costs =	385.3	249.4
2nd Year Capital Costs =	644.1	416.9
1st Year Solid Fuel Working Capital Costs =	3.2	3.3
2nd Year Solid Fuel Working Capital Costs =	5.6	5.7
1st Year Fixed O&M Costs =	18.6	13.4
2nd Year Fixed O&M Costs =	33.1	23.7
1st Year Variable O&M Costs =	8.2	8.2
2nd Year Variable O&M Costs =	13.8	13.9
1st Year Capital Replacement Costs =	1.7	1.7
2nd Year Capital Replacement Costs =	3.0	3.0

Total Non-Fuel Costs for First 12 Months of Operation (Nominal $, millions)

	FGPP 1	FGPP 2
1st Year Capital Costs =	385.3	249.4
2nd Year Capital Costs =	268.4	173.7
1st Year Solid Fuel Working Capital Costs =	3.2	3.3
2nd Year Solid Fuel Working Capital Costs =	2.3	2.4
1st Year Fixed O&M Costs =	18.6	13.4
2nd Year Fixed O&M Costs =	13.8	9.9
1st Year Variable O&M Costs =	8.2	8.2
2nd Year Variable O&M Costs =	5.7	5.8
1st Year Capital Replacement Costs =	1.7	1.7
2nd Year Capital Replacement Costs =	1.2	1.2
Total Non-Fuel Costs for First 12 Months =	**708.5**	**469.0**

Notes: (1) *Variable O&M costs are based on Scenario 1A.*
(2) All costs assume the in-service date shown above and do not reflect cost changes that may occur due to changes in indices for indexed costs from what was assumed in the economic analyses or changes that may occur for other reasons.

Fuel Diversity Analysis Results: FPL System Fuel Mix Projections by Plan

Scenario: 1A

	Plan with Coal					Plan without Coal					Differential Plan with Coal vs Plan without Coal				
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11) = (1) - (6)	(12) = (2) - (7)	(13) = (3) - (8)	(14) = (4) -(9)	(15) = (5) -(10)
Year	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)
------	------	------	------	------	------	------	------	------	------	------	------	------	------	------	------
2012	11.5%	62.0%	8.0%	17.4%	1.1%	11.5%	65.1%	5.0%	17.4%	1.1%	0.0%	-3.0%	3.0%	0.0%	0.0%
2013	14.5%	60.7%	6.7%	16.9%	1.1%	11.2%	65.5%	5.2%	16.9%	1.1%	3.3%	-4.8%	1.5%	0.0%	0.0%
2014	19.6%	57.2%	5.3%	16.7%	1.2%	10.9%	67.0%	4.1%	16.7%	1.2%	8.6%	-9.7%	1.1%	0.0%	0.0%
2015	20.9%	58.2%	3.5%	16.0%	1.3%	10.4%	67.3%	4.9%	16.0%	1.3%	10.5%	-9.1%	-1.4%	0.0%	0.0%
2016	17.6%	60.4%	5.1%	15.6%	1.3%	7.3%	71.1%	4.6%	15.6%	1.3%	10.3%	-10.7%	0.4%	0.0%	0.0%

Scenario: 4D

	Plan with Coal					Plan without Coal					Differential Plan with Coal vs Plan without Coal				
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11) = (1) - (6)	(12) = (2) - (7)	(13) = (3) - (8)	(14) = (4) -(9)	(15) = (5) -(10)
Year	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)
------	------	------	------	------	------	------	------	------	------	------	------	------	------	------	------
2012	10.3%	62.8%	8.5%	17.4%	1.1%	9.8%	65.6%	6.1%	17.4%	1.1%	0.4%	-2.9%	2.4%	0.0%	0.0%
2013	13.2%	61.0%	7.7%	16.9%	1.1%	9.7%	66.2%	6.0%	16.9%	1.1%	3.5%	-5.2%	1.7%	0.0%	0.0%
2014	17.7%	58.2%	6.2%	16.7%	1.2%	9.2%	68.0%	4.9%	16.7%	1.2%	8.5%	-9.8%	1.3%	0.0%	0.0%
2015	18.8%	59.5%	4.3%	16.0%	1.3%	8.7%	68.4%	5.5%	16.0%	1.3%	10.1%	-9.0%	-1.2%	0.0%	0.0%
2016	15.9%	61.3%	5.8%	15.6%	1.3%	5.9%	71.7%	5.5%	15.6%	1.3%	10.0%	-10.3%	0.3%	0.0%	0.0%