BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070602-EI
FLORIDA POWER & LIGHT COMPANY

IN RE: FLORIDA POWER & LIGHT COMPANY'S PETITION TO DETERMINE NEED FOR EXPANSION OF ELECTRICAL POWER PLANTS

DIRECT TESTIMONY & EXHIBITS OF:

STEVEN R. SIM

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF STEVEN R. SIM

DOCKET NO. 07_____ - EI

SEPTEMBER 17, 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 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 any exhibits in this case?

A. Yes. I am sponsoring the following Exhibits SRS-1 through SRS-12, which are attached to my direct testimony:

Exhibit SRS-1	Projection of FPL's 2007 - 2020 Capacity Needs
Exhibit SRS-2	Projected Incremental FPL DSM: 2006 – 2020
Exhibit SRS-3	Projection of FPL's 2007 – 2020 Capacity Needs: with Proposed Nuclear Capacity Uprates
Exhibit SRS-4	The Two Resource Plans Utilized in the Analyses

Exhibit SRS-5	Assumptions Used in the Analyses
Exhibit SRS-6	Economic Analysis Results for One Fuel and Environmental Compliance Cost Scenario
Exhibit SRS-7	Economic Analysis Results: Total Costs and Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios
Exhibit SRS-8	Economic Analysis Results: Matrix of Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios
Exhibit SRS-9	Economic Analysis Results: Projection of Nuclear Uprates Non-Fuel Costs for the First 12 Months of Operation
Exhibit SRS-10	Economic Analysis Results: Projection of Approximate Bill Impacts With Nuclear Uprates: 2009 - 2013
Exhibit SRS-11	Non-Economic Analysis Results: FPL System Fuel Mix Projections by Plan
Exhibit SRS-12	Non-Economic Analysis Results: Cumulative FPL System CO_2 Emission Reductions from Nuclear Uprates

Q. What is the scope of your testimony?

A. My testimony addresses ten main points:

(1) I briefly discuss FPL's integrated resource planning (IRP) process and describe how the application of the IRP process in 2006/2007 focused in large part on maintaining/enhancing fuel diversity in FPL's system.

(2) I identify FPL's additional resource needs for 2007 - 2020, with particular emphasis on 2012 and 2013, and explain how these needs were determined.

(3) I discuss why DSM cannot eliminate these resource needs.

(4) I present an overview of the analytical approach used to evaluate the nuclear capacity uprates for FPL's four existing nuclear generating units - Turkey Point Nuclear Units 3 & 4 and St. Lucie Nuclear Units 1 & 2 - versus the most likely non-nuclear competing technology available in that time frame, natural gas-fired combined cycle (CC) capacity, from both an economic and a non-economic perspective.

(5) I discuss two resource plans: one plan assuming the capacity uprates are performed in the 2011 - 2012 time period and a second plan assuming that the capacity uprates are not performed.

(6) I describe FPL's use of various fuel cost forecasts and environmental compliance cost forecasts that were combined into 9 fuel cost and environmental compliance cost scenarios which were used in the analyses of the two resource plans.

(7) I present the results of FPL's economic analyses of the two resource plans, which include projections of revenue requirements for the projected operating lives of the nuclear units for each scenario, non-fuel costs for the

first 12 months of operation of the uprated units, and approximate customer bill impacts.

(8) I present the results of the non-economic analyses of the two resource plans which include projections of system fuel mix by fuel type and system carbon dioxide (CO2) emissions.

(9) I discuss the adverse consequences in regard to economics, system fuel diversity, and CO2 emissions that would occur if a Need Determination for the nuclear capacity uprates is not approved.

(10) I present the conclusions I draw from the above referenced analyses.

Q. What is your primary conclusion?

A. Based on the analyses that have been performed, adding the capacity uprates for FPL's four existing nuclear units is a better, more cost-effective choice than not adding the capacity uprates for addressing FPL's future capacity needs and for both maintaining/enhancing fuel diversity and lowering FPL's CO2 system emissions.

Q. Please summarize your testimony.

A. FPL's 2006/2007 resource planning work determined that FPL has future resource needs for 2012 of 490 MW of incremental capacity (power plant construction and/or new purchases) or 408 MW at the generator of additional cost-effective DSM. The resource needs for 2012 and 2013 combined are 907 MW of incremental capacity or 756 MW of additional cost-effective DSM. All DSM that has been identified to be cost-effective through 2013 has already been reflected in FPL's 2006/2007 resource planning work.

Consequently, FPL could not meet its resource needs through 2013 with DSM. Therefore, in order to meet FPL's Summer reserve margin criterion of 20% through 2013, FPL needs new capacity (power plant construction and/or purchases).

FPL's resource planning work also projects a cumulative capacity need of 6,570 MW through 2020. This large capacity need provides significant opportunities for a wide variety of options - new fossil units, renewable energy options, DSM and other energy efficiency options (such as building standards and appliance standards), and new nuclear units – to play a role in FPL's resource plans.

FPL also determined that a key objective during this resource planning cycle was to select capacity options that would maintain/enhance FPL's system fuel diversity. The nuclear capacity uprates offer the unique opportunity to add significant increases in nuclear capacity and energy starting in 2011, a number of years before additional capacity and energy from new nuclear units would be possible. Other unique aspects of the nuclear uprates option are that it is an option that can only be supplied by one party, an electric utility (such as FPL) with existing nuclear units for which uprates are possible, and once fully implemented, is unlikely to be replicated.

FPL developed a Plan with Nuclear Uprates that included these relatively near-term nuclear capacity and energy additions. An alternate Plan without Nuclear Uprates was developed in order to determine the economic and non-economic impacts of adding the nuclear capacity uprates. FPL's analyses compared these two resource plans under 9 scenarios of forecasted fuel costs and environmental compliance costs.

The economic analyses show that the nuclear capacity uprates are the lowest cost alternative for FPL and its customers in 8 of 9 scenarios with an economic advantage for those 8 scenarios that ranged from $122 million in cumulative present value of revenue requirements in 2007$ (CPVRR) to $863 million CPVRR. The only scenario in which the nuclear uprates do not have an economic advantage is the lone scenario that features both a low gas cost forecast and a low environmental compliance cost forecast. However, in that scenario, the total CPVRR cost for the Plan with Nuclear Uprates is at least $33 billion less expensive than the costs for either plan in any of the other 8 scenarios. Consequently, FPL's customers would still benefit in this scenario from the large amounts of gas on FPL's system and the forecasted low gas costs.

Non-fuel costs for the first 12 months of operation of each of the uprated nuclear units range from approximately $59.8 million to $76.4 million. A customer bill impact of approximately $0.21 to $1.79 per 1,000 kwh is projected for the 2009 – 2013 time frame.

The non-economic analyses show that the Plan with Nuclear Uprates has advantages in regard to both system fuel diversity and lowering system CO_2 emissions compared to the Plan without Nuclear Uprates. The Plan with Nuclear Uprates is projected to increase FPL's reliance upon nuclear energy by 2%, and to lower FPL's dependence upon natural gas by the same percentage, in the system fuel mix by 2013. This increase in the annual amount of nuclear energy produced from the uprates is equivalent in 2013 to the annual total electrical usage of approximately 213,000 residential customers. The Plan with Nuclear Uprates is also projected to achieve a cumulative reduction in system CO_2 emissions of more than 27 million tons through 2043, the year in which the current operating licenses for the four nuclear units are set to end.

In summary, the nuclear uprates represent a unique resource addition opportunity from which FPL's customers will benefit from the perspectives of economics, system fuel diversity, and CO_2 emissions. The uprates will immediately result in fuel cost savings, greater fuel diversity, and reduced CO_2 emissions. The additional capacity supplied by the uprates could also contribute to deferral of new capacity additions in the 2014 – 2017 time period.

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 has been used and refined 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 I'll refer to as 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 CPVRR costs. The lowest total CPVRR cost perspective in these cases is the same as the lowest average electric rate perspective, because the number of kilowatthours over which the costs are distributed does not change, as would be the case when DSM resources are being examined.

However, the decision of what type of resources should be added is also influenced by considerations such as whether a resource can be brought into service on FPL's system in time to meet a projected resource need and whether a given resource or resource 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 quantitative, but non-economic, terms such as percentages, etc. rather than in terms of dollars.

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

A. One of the system concerns is 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/enhancing system fuel diversity. FPL's IRP work in 2006/2007 has directly addressed this concern. Accordingly, in addition to the proposal in this filing to implement the capacity uprates for FPL's four existing nuclear generating units, FPL expects to seek approval for the addition of two new nuclear units to address FPL's capacity needs in 2018 and 2020, respectively. Maintaining, and enhancing if possible, system fuel diversity will continue to be an issue that FPL's resource planning work addresses in coming years.

A third system concern, that of moving in the direction of lowering utility system CO2 emissions over the long-term, has been prompted by growing interest in reducing greenhouse gas emissions.

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 resource plans are best for FPL's system, both 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 resource plan.

Q. **Did FPL utilize its IRP process in the analyses that supports its request in this case for a determination of need for capacity uprates at its four existing nuclear generating units?**

A. Yes. FPL utilized its IRP process first to determine the timing and magnitude of resource needs over a multi-year period. It was determined that FPL's first resource need was in 2012 and that this resource need increased every year thereafter. Second, FPL identified resource options and resource plans that could meet these capacity needs. FPL then determined through economic analyses what the CPVRR costs were for these competing resource plans.

In addition, the impacts on FPL's system in regard to maintaining/enhancing system fuel diversity and of lowering system CO_2 emissions were determined for each of these resource plans.

Q. In its analyses, what in-service dates were assumed for the capacity uprates at FPL's four nuclear units?

A. For purposes of its analyses, FPL assumed the targeted in-service dates for the nuclear uprates: December 2011 for St. Lucie 1, May 2012 for Turkey Point 3, June 2012 for St. Lucie 2, and December 2012 for Turkey Point 4. However, as noted by FPL witness Hale, those dates could slip due to potential delays in the NRC or other approval processes, and material and equipment deliveries from third party vendors.

II. FPL's Future Resource Needs

Q. How did FPL determine it needed additional resources and what are the magnitudes 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 Summer and Winter 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 currently believes is necessary to ensure reliable service, and which 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, FPL's projected need for additional resources has been driven by the Summer reserve margin criterion. This again was the case in FPL's 2006/2007 reliability assessment work 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%.

The additional incremental MW needed by the Summer of 2012 is projected to be 490 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, (490 MW/1.20 =) 408 MW if provided by a DSM-based reduction to the forecasted peak load.

The similar incremental need values for the Summers of 2013 - 2020, respectively, are an additional 417 MW (supply) or 348 MW (DSM) for 2013, an additional 450 MW (supply) or 375 MW (DSM) for 2014, an additional 639 MW (supply) or 533 MW (DSM) for 2015, an additional 1,933 MW (supply) or 1,611 MW (DSM) for 2016, an additional 659 MW (supply) or 549 MW (DSM) for 2017, an additional 645 MW (supply) or 538 MW (DSM) for 2018, an additional 641 MW (supply) or 534 MW (DSM) for 2019, and an additional 696 MW (supply) or 580 MW (DSM) for 2020. Furthermore, the trend of annual increased resource needs of at least 600 MW (supply) or 500 MW (DSM) continues after 2020.

These incremental annual resource need values add to a cumulative need value for 2012 - 2020 of approximately 6,570 MW if the resource need is to be met by supply options. The corresponding cumulative resource need for this period is approximately 5,475 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 - 2020 if the resource needs are to be met by supply options are shown in Exhibit 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. This projection of capacity needs was used in the development of the two resource plans analyzed for this filing.

These projections rely upon FPL's IRP 2006 load forecast that was developed in September 2006 and used in FPL's recent Need filing for advanced technology coal units. This same load forecast was used in the economic and non-economic analyses discussed in the remainder of my testimony. Other assumptions used in this capacity need projection are discussed later in my testimony.

Q. Why is it important to project capacity needs through 2020 in this filing which addresses nuclear uprate capacity additions in 2011 and 2012?

A. The projection of capacity needs through 2020 is used in this filing to help develop the resource plans that are compared in the economic and non-economic analyses.

Q. Do these resource need projections take into account the proposed capacity uprates to FPL's existing four nuclear units?

A. No. The projections presented in Exhibit SRS-1 do not include the impact of any new FPL generating units or additional generating capacity from existing FPL generating units after the WCEC 1 and 2 units are added in 2009 and 2010, respectively. Therefore, the approximate 414 MW of proposed capacity uprates to FPL's four existing nuclear units in the 2011 and 2012 time period are not accounted for in these capacity need projections.

If the capacity from the uprates had been included in this projection, FPL's projected resource needs would have been 310 MW lower in the Summer of 2012 and 414 MW lower in the Summer of 2013 and beyond. (As previously discussed, the first three uprates are assumed to come in-service in December 2011, May 2012, and June 2012, respectively. Therefore, the 310 MW of capacity from these three units is accounted for in Summer reserve margin calculations beginning with the Summer of 2012. The fourth uprate is assumed to come in-service in December 2012. Therefore, its 104 MW of capacity is accounted for in Summer reserve margin calculations beginning with the Summer of 2013.)

Q. Do these resource need projections take into account any projections of purchased power beyond what is currently under contract?

A. Yes. For purposes of the analyses conducted for this filing, FPL has included the capacity and energy contributions from 6 renewable energy purchases not currently under contract for the 2009 – on time period. Three of these assumed purchases are extensions of current purchases from municipal waste-to-energy facilities. The current contracts for these three purchases are scheduled to end in the time period from August 2009 to December 2010. The current total capacity under contract from these three purchases is 143 MW. However, new contractual arrangements have not yet been developed.

In addition, FPL has received three firm capacity proposals in response to its recent Renewable Request for Proposals (RFP). These three proposals, one from a waste-to-energy facility and two from biomass facilities, would provide a total of 144 MW of capacity starting between March 2011 and January 2012 with proposed end dates ranging from 2021 to 2036. At the time of this filing, FPL is analyzing these three firm capacity proposals.

Although no contracts have been developed in regard to any of these 6 renewable capacity options, for purposes of the analyses conducted for this filing, FPL is assuming that all 287 MW of firm capacity would be in place to serve FPL's customers. The 143 MW from the three municipal waste-to-energy facilities currently under contract is assumed to continue through 2026 when other contracts for smaller capacity amounts from these same facilities are scheduled to end. The 144 MW from the three renewable RFP proposals are assumed to be in place through their proposed end dates.

Arguably, assuming that every MW from these renewable options will be available and realized for the benefit of FPL's customers might be considered overly, if not unduly, optimistic. However, at the very least, it serves to provide a conservative projection of FPL's future resource needs by lowering FPL's projected resource needs by 287 MW.

Q. Why is the 1,933 MW incremental capacity need for 2016 so much larger than for the other years in the 2012 – 2020 time period?

A. In addition to the forecasted peak load growth in 2016, two significant power purchases are projected to no longer be providing capacity and energy to FPL starting in 2016. One of these is a 931 MW power purchase agreement with the Southern Company that expires at the end of 2015. The other is a 381 MW power purchase from the St. Johns River Power Park (SJRPP). Due to Internal Revenue Service regulations, FPL will no longer be able to receive capacity and energy from that agreement once a certain amount of energy has been received. FPL currently estimates that this point will be reached at the end of 2015. After accounting for the loss of these two capacity resources, the remaining capacity need solely attributed to FPL system growth is 621 MW (=1,933 – 931 – 381). This 621 MW capacity amount attributable solely to projected load growth is similar to the annual capacity need amounts described earlier for other years.

III. Demand Side Management

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

A. Yes. These projections already incorporate all of the cost-effective DSM currently identified by FPL through the year 2014 plus a projection of continued DSM implementation for 2015 – 2020 at currently projected annual implementation rates. This amount of DSM includes not only FPL's current DSM Goals, but also a significant amount of additional DSM through 2014 that FPL has identified as cost-effective, and which the Florida Public Service Commission has approved, since the current DSM Goals were approved. Furthermore, these projections include an assumption that FPL will continue to implement additional, cost-effective DSM for each of the remaining years 2015 through 2020 at the projected implementation rates for the years immediately preceding 2015.

FPL now projects implementing approximately 1,899 MW at the generator of additional Summer DSM demand reduction capability from August 2006 through August 2020, of which 1,025 MW (= 2,516 MW in 2013 – 1,491 MW in 2006) at the generator will be implemented from August 2006 through August 2013, as presented in Exhibit SRS-2. This amount of additional DSM is incorporated into the projection of FPL's resource needs presented in Exhibit SRS-1 and discussed above.

The 1,025 MW of incremental DSM by August 2013 is equivalent, after accounting for reserve margin requirements, to 1,200 MW of additional capacity need by 2013 that would otherwise exist without FPL's DSM plans. This amount of additional DSM by 2013 is, therefore, also equivalent to a new 1,219 MW 3x1 G CC unit identical in size to the CC units being built at FPL's WCEC site with which that additional 2013 capacity need could have been met. The continued implementation of significant amounts of cost-effective DSM such as the 1,025 MW of additional DSM by 2013 is consistent with FPL's position as an industry leader in DSM.

Q. Could FPL meet all of its resource needs through 2013 with DSM?

A. No. As discussed above, FPL's projected resource needs presented in Exhibit SRS-1 already account for all of the reasonably achievable, cost-effective levels of DSM identified by FPL through 2013 as is presented in Exhibit SRS-2. Consequently, FPL cannot meet its incremental resource needs through 2013 with additional, cost-effective DSM. These resource needs will need to 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. Overview of the Approach Used to Analyze the Nuclear Capacity Uprates

Q. Please provide an overview of the analytical approach FPL used to evaluate the impacts of uprating the capacity at FPL's four existing nuclear generating units.

A. The analytical approach FPL utilized can be summarized as follows. First, FPL developed one resource plan that includes the capacity uprates at FPL's four existing nuclear units. This resource plan is referred to in this filing as the Plan with Nuclear Uprates. FPL next developed a second or alternate resource plan that does not include these capacity uprates, referred to in this filing as the Plan without Nuclear Uprates.

These resource plans assumed specific units for the 2011 – 2017 time period. Both plans also assumed the addition of two proposed new nuclear units at FPL's existing Turkey Point site, Turkey Point 6 in 2018 and Turkey Point 7 in 2020; and both plans utilized generic unsited "filler" units for the 2021 – on time period. These resource plans are discussed in more detail later in my testimony. Second, economic and non-economic analyses were then carried out to compare the two resource plans.

The economic analyses primarily consisted of a comparison of the CPVRR costs in 2007$ for the two plans for 2007 – 2043 for various scenarios of fuel and environmental compliance costs. This analysis allows the total system costs (capital, fuel, O&M, etc.) with the nuclear capacity uprates to be compared to total system costs without the uprates for all years through the year in which the last operating license for FPL's four existing nuclear units ends (2043). In addition, projections of a portion of these total system costs, specifically the non-fuel costs, for the first 12 months of operation for each uprated nuclear unit, were made. An approximate customer bill impact for the 2009 – 2013 time period was also calculated.

The non-economic analysis comprised two projections. First, projections were made of FPL's system fuel mix for the two resource plans for the fuel and environmental compliance cost scenarios. This analysis allows the fuel diversity impacts of the addition of the nuclear capacity uprates to be determined. In addition, projections of FPL's system CO2 emissions were made for the two plans, thus allowing a calculation of the CO2 emission reduction impact from the nuclear uprates to be made.

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

A. It is not only appropriate to do this, but also necessary if one is to fully capture and fairly compare all of the economic and non-economic impacts of different capacity options that could be added to a utility 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.

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 for the 2011 - 2017 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 used for 2021 – on (i.e., after assumed 2018 and 2020 new nuclear units have been added in both of the two resource plans). In this way the two resource plans being compared 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 Resource Assessment & Planning'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, variable O&M, and environmental compliance costs) in its production costing calculations, projects the annual emission levels associated with the resource plans, and incorporates the effects of system transmission transfer limits on the dispatch of generating units. This integrated model approach was used in FPL's recent advanced technology coal unit filing.

An additional spreadsheet was also used in analyzing the resource plans. This spreadsheet was used to download the annual emission levels projected in P-MArea and then to calculate the net annual costs for those emissions after allowances, if applicable, are accounted for.

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

A. In regard to the economic analyses, the basis of comparison was CPVRR costs for the two resource plans for the various fuel and environmental compliance cost scenarios.

In regard to the non-economic analyses, there are two bases of comparison. The first basis of comparison is a projection of annual system energy by fuel type, or system fuel mix, for the two resource plans using the same fuel cost and environmental compliance costs scenarios. The system fuel mix projections are for the 2011 through 2013 time frame. This three-year time frame was chosen because it addresses the time period starting when the first nuclear capacity uprate is assumed to come in-service (2011) through the first year that all of the nuclear capacity uprates are in-service for a full year (2013).

The second basis of comparison is a projection of cumulative CO2 emission reductions for the FPL system due to the nuclear uprates. The time frame for this projection is from 2013 through 2043. This time frame addresses the first year in which all of the nuclear capacity uprates are in-service for a full year (2013) through the year in which the last of the current operating licenses for FPL's existing nuclear units ends (2043).

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 – for example, nuclear and CC units – that use different types of fuel, namely uranium and natural gas, and which have different emission profiles, three different fuel cost forecasts and four different environmental compliance cost forecasts were used in the analyses. These three fuel cost forecasts and four environmental compliance cost forecasts could be combined into 12 potential scenarios of forecasted fuel costs and environmental compliance costs. After considering these 12 possible scenarios, it was determined that three of the scenarios, those with a low gas cost forecast and a medium-to-high CO2 environmental compliance cost forecast, were very unlikely to occur. Consequently, these three scenarios were dropped from further consideration and FPL utilized 9 scenarios of fuel cost forecasts and environmental compliance cost forecasts in its analyses.

V. The Two Resource Plans Utilized in the Analyses

Q. Please discuss the development of the two resource plans used in the analyses.

A. In order to fully evaluate the system impacts of the nuclear capacity uprates, FPL first needed to develop a long-term resource plan that included the capacity uprates. This resource plan is labeled as the Plan with Nuclear Uprates. In addition, FPL needed to develop an alternate resource plan not including the nuclear capacity uprates that could be used in comparative analyses with the Plan with Nuclear Uprates. This alternate plan is labeled as the Plan without Nuclear Uprates.

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 that FPL currently believes is necessary to provide reliable service. 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 to the extent possible. Third, the resource plans should focus as much as possible on the assumed in-service or decision years in question, 2011 and 2012, 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, Exhibit SRS-3 was developed to present a revised projection of FPL's capacity needs assuming that the nuclear capacity uprates are added in 2011 and 2012. By comparing this document with Exhibit SRS-1, it is clear that the capacity needs are lower by 310 MW for 2012 and by 414 MW for 2013 - on.

Exhibits SRS-1 and SRS- 3 were then utilized to develop the two resource plans. These two plans are presented in Exhibit SRS-4. The two resource plans meet all of the criteria discussed above.

Q. Is the Plan with Nuclear Uprates a dynamic long-term resource plan?

A. Yes. By definition, any long-term resource plan, including both the Plan with Nuclear Uprates and the Plan without Nuclear Uprates, is a dynamic plan that is subject to change as conditions change. Consequently, this plan does not necessarily identify FPL's definitive long-term resource additions.

As demonstrated throughout this filing, FPL believes that the uprates included in the Plan with Nuclear Uprates represent the best choice for meeting FPL's future capacity needs and for maintaining/enhancing fuel diversity in FPL's system and for lowering FPL system CO2 emissions.

The other capacity additions shown in the Plan with Nuclear Uprates (and all capacity additions shown in the Plan without Nuclear Uprates) in the 2011 – 2017 time period are reasonable assumptions for meeting system capacity need requirements at the time of this filing. All other capacity additions in the Plan with Nuclear Uprates, and all capacity additions in the Plan without Nuclear Uprates, for the 2011 – 2017 time period are assumed to be new CC unit additions.

To-date, none of the new advanced technology coal generating units for which recent approval has been sought in Florida has received both Need and permitting approval. Therefore, it appears possible that any new generating unit additions in the relative near-term will be gas-fired. Consequently, the new units included, for analysis purposes, in these resource plans in the 2011 – 2017 time period are CC units similar to the 3x1 G CC units being built at FPL's WCEC site or 2x1 G CC units. However, because FPL is not at this time making definitive selections for 2011, or for the years after 2011, these CC additions included in the Plan with Nuclear Uprates would be re-evaluated in the future using updated information when it is necessary to make those resource decisions. FPL will evaluate a variety of resource options including gas-fired and coal-fired generating units, power purchases, renewable energy options, and additional DSM prior to making its eventual decision on how best to meet its resource needs for the 2011 – 2017 time period and for the 2021 – on time period. The new nuclear units included in this plan in 2018 and 2020 are units that FPL expects to propose in a separate Need filing.

In addition, as previously discussed, for purposes of these analyses FPL has included 6 renewable energy purchases totaling 287 MW. At the time of this filing no contracts regarding any of these 6 capacity options have been entered into.

Therefore, although a number of the capacity additions assumed for the Plan with Nuclear Uprates may ultimately change in the future due to re-evaluation and/or evolving factors, these capacity additions are reasonable and representative additions for all years for analysis purposes. Regardless of whether these other capacity additions may change, FPL believes such changes would be applicable to both resource plans so that the centerpiece of the Plan with Nuclear Uprates, the nuclear uprates themselves, will remain the best option to add. The uprates will provide capacity to meet FPL's future resource needs and will maintain/enhance fuel diversity and lower system CO_2 emissions.

Q. In developing the resource plans, what assumptions were made in regard to the near-term, 2011 - 2017, capacity additions?

A. All capacity additions in both plans were assumed to be new unit additions. In developing the resource plans presented in Exhibit SRS-4, several assumptions were made regarding the new unit additions for 2011 - 2017 time period for both resource plans.

First, it was assumed for analytical purposes that all new unit additions in the 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. Second, sites for the assumed CC units in the 2011 – 2017 time period are generally not known (in large part because no decision to build these new CC units has been made as discussed above). However, in order to develop costing for these assumed CC units, costs and performance characteristics for a greenfield CC of similar design and capacity as the two 3x1 G CC units being constructed at FPL's WCEC site were used.

Third, in regard to the size of the CC units included in the two resource plans in the 2011 – 2016 time period for the Plan with Nuclear Uprates, and for 2011 – 2017 for the Plan without Nuclear Uprates, the same size (1,219 Summer MW representing a 3x1 G CC unit) as the WCEC units was assumed. For 2017 for the Plan with Nuclear Uprates, a 2x1 G CC unit with a capacity of 812 MW was assumed.

Exhibit SRS-5 provides a listing of assumptions used in creating, and analyzing, the two resource plans, including the cost and performance assumptions for the new CC units and the financial/economic assumptions.

Q. Please discuss the 3x1 CC unit in 2011 assumed for both resource plans.

A. Because FPL is constructing 3x1 CC units with in-service dates of 2009 and 2010 at its WCEC site, it is anticipated that significant construction cost savings are possible if a third unit of identical design could be built for 2011 at a location near the WCEC site because key personnel in regard to the engineering and construction of the units could move from the WCEC 1 & 2 work directly to the construction of the 2011 unit. Second, FPL's preliminary analyses show that system fuel savings from an earlier (2011 instead of 2012)

3x1 CC unit would be beneficial to FPL's customers even without these potential construction cost savings if an earlier unit could be built.

Although FPL has made no firm decisions at the time of this filing to proceed with a 2011 CC, for analysis purposes in this filing it was decided to assume that such a unit would be included in both resource plans.

Q. How does the assumption of a 2011 CC unit impact the economic and non-economic analyses of the two resource plans?

A. The assumption of a 2011 CC unit in both resource plans, compared to a 2012 date for the addition of this same unit, affects the two plans only in the years 2011 and 2012 (assuming a June in-service date in either year). It is not possible to provide an accurate projection of the full economic impact because a site would first have to be chosen for the 2011 or 2012 unit, with construction cost estimates then developed for that site. In regard to system fuel savings, the economic impact is to lower the system costs in 2011 and 2012 for both resource plans due to the earlier introduction of the fuel-efficient unit. However, these fuel savings would likely be greater for the Plan with Nuclear Uprates because the projected outages required for FPL's existing nuclear units to prepare for the uprates will be longer than the outages that would occur routinely without the uprates (as is the case in the Plan without Nuclear Uprates.) Therefore, the earlier introduction of the fuel-efficient CC unit in 2011 would provide more fuel savings for the Plan with

Nuclear Uprates because of the longer nuclear outages required in that resource plan.

In regard to the non-economic analyses, the primary impact would be to lower system CO2 emissions earlier than would be the case if the 2011 unit had been brought into service a year later.

Q. Assuming that a CC unit was advanced to 2011 for economic reasons as previously discussed, the CC unit's capacity would fully address FPL's 2012 capacity need. In this case would the capacity from the nuclear uprates still contribute to meeting FPL's future capacity needs?

A. Yes. As shown in Exhibit SRS-4, without the uprates FPL would need to add additional capacity in 2014. This is shown in the Plan without Nuclear Uprates by the introduction of another 3x1 CC unit in 2014. However, the 414 MW of new capacity provided by the nuclear uprates are sufficient to defer this new 2014 unit to 2015, as shown in the Plan with Nuclear Uprates. The 414 MW of capacity from the uprates are also expected to result in additional deferral of new units and/or a reduction in the size of the new units that might be built as seen by comparing the two resource plans for the years 2016 and 2017 in this exhibit. Therefore, the nuclear uprates will definitely contribute to meeting FPL's future capacity needs even if a CC unit were advanced to 2011 for economic reasons.

Q. In developing the resource plans, what assumptions were made in regard to additions for the period 2018 - on?

A. Both plans assumed that new nuclear generating units at FPL's existing Turkey Point site are added, one unit in 2018 and one in 2020. The remainder of FPL's capacity needs for 2021-on are assumed to be met by the requisite number of unsited 2x1 F CC filler units to meet FPL's system reserve margin requirements. The total number of these filler units in both resource plans is identical as shown in Exhibit SRS-4. The decision to utilize 2x1 F CC units as the filler units for the 2021-on time period was made to minimize the potential impact that differences in unit types for filler units between the two resource plans in these latter years might have on the analysis results. And, as previously discussed for the capacity options included in the resource plans for the 2011 – 2017 time period, these 2x1 F CC filler units added in the 2021 – on time period do not represent FPL's definitive resource plan for those years. They are utilized for analysis purposes solely to better focus the analysis on the resource decision years of 2011 and 2012.

Q. In considering the resource options included in these two resource plans, are there unique aspects to the nuclear uprates option?

A. Yes. The nuclear uprates option is unique in several respects. First, it is a limited resource in the sense that only an electric utility with existing nuclear capacity can offer new nuclear capacity through uprates. Second, because it is highly unlikely that one electric utility would offer additional nuclear capacity from an existing nuclear unit to another electric utility, nuclear uprate capacity can only be delivered by the electric utility with the nuclear uprate potential.

Third, nuclear uprates offer the potential for providing new nuclear capacity years in advance of when new nuclear units can be built.

Thus there are significant differences between the nuclear uprates option and all other resource options – new fossil units, renewable energy options, DSM and other energy efficiency options (such as building and appliance standards), and new nuclear units – that are included directly and/or indirectly in these two resource plans. All of these other options will have multiple opportunities to address the 6,570 MW of capacity need projected on FPL's system through 2020 through the construction/implementation of additional "units" of each of these options. In addition, with the likely exception of new nuclear units, it is likely that these options could be delivered or offered to FPL by more than one party.

By comparison, the nuclear uprates option can be delivered by only one party (FPL), can be delivered relatively quickly, and once fully implemented, will not be replicated. From those perspectives the nuclear uprates option is a unique resource option.

VI. 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., nuclear units and natural gas units, it is appropriate that different fuel cost forecasts be utilized to analyze the relative economics between the 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 nuclear fuel.

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, three different fossil fuel cost forecasts that reflect a reasonable range of future fossil fuel costs were developed and used in these analyses. These three fossil fuel cost forecasts are referred to as the High Gas Cost forecast (High Gas Cost), the Medium Gas Cost forecast (Medium Gas Cost), and the Low Gas Cost forecast (Low Gas Cost). As indicated by this naming convention, the High Gas Cost forecast projects high natural gas costs, the Medium Gas Cost forecast projects medium natural gas costs, and the Low Gas Cost forecast projects low natural gas costs. In addition, forecasted nuclear fuel costs were also developed and used in the analyses.

FPL witness Yupp addresses the fossil fuel cost forecasts in his testimony and FPL witness Villard addresses the forecasted nuclear fuel costs in his testimony.

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 when comparing nuclear 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. These environmental compliance cost forecasts addressed four emissions: sulfur dioxide (SO2), nitrogen oxides (NOx), mercury (Hg), and CO2.

As is the case with future fuel costs, there are also a large number of possible 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, four different environmental compliance cost forecasts that reflect a reasonable range of future environmental compliance costs were developed and used in these analyses. These four environmental compliance cost forecasts are referred to as Env I through Env IV. FPL witness Kosky addresses the environmental compliance cost forecasts in his testimony.

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

A. As previously discussed, FPL initially combined the three fuel cost forecasts with the four environmental compliance cost forecasts to develop a total of 12 initial scenarios of forecasted fuel costs and environmental compliance costs. Then, after examining the different scenarios, FPL removed from further consideration three scenarios comprised of a low natural gas cost forecast and medium-to-high environmental compliance cost forecasts for CO_2 based on FPL's belief that medium-to-high environmental compliance costs for CO_2 will result in upward pressure on natural gas prices. In other words, an assumption of medium-to-high environmental compliance costs for CO_2 is incompatible with an assumption of low natural gas prices. Each of the remaining 9 scenarios was then utilized separately in both the economic and non-economic analyses of the two resource plans.

Because the fuel cost forecasts are designated as High Gas Cost, Medium Gas Cost, and Low Gas Cost, and the environmental compliance cost forecasts are designated as Env I through Env IV, the 9 scenarios of fuel costs and environmental compliance costs are designated as High Gas Cost Env I through High Gas Cost Env IV, Medium Gas Cost Env I through Medium Gas Cost Env IV, and Low Gas Cost Env I. (The three eliminated scenarios were initially labeled as Low Gas Cost Env II, Low Gas Cost Env III, and Low Gas Cost Env IV.)

VII. Results of the Economic Analyses

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

A. The economic analysis approach utilized for analyzing the nuclear capacity uprates on FPL's system primarily consisted of comparing the CPVRR costs for the Plan with Nuclear Uprates and the Plan without Nuclear Uprates for all years through the year in which the operating licenses for FPL's four existing nuclear units ends (2043). The analysis approach used in this step was virtually identical to the approach used in FPL's most recent Need filings (i.e., the filings for the Turkey Point 5, the West County Energy Center 1 and 2, and the advanced technology coal generating units).

However, there is one difference in the analytical approach as applied for the nuclear capacity uprates. The cost of transmission losses for the resource plans is not included because there are no known sites for the CC units included in both resource plans. Consequently, it is not possible to calculate losses for the two plans.

Q. What costs are included in the economic analysis?

A. The economic analysis addresses total system costs for the FPL system including all fixed and variable costs, upstream gas costs, and cost of capital impacts for the two plans.

However, in the analyses of these two resource plans, upstream gas costs and cost of capital impacts (i.e., net equity adjustment) calculations were not included. The upstream gas cost adder is essentially used to account for any additional gas transportation infrastructure cost resulting from 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, the cost of capital impacts were already accounted for by assuming an incremental 55.8% equity / 44.2% debt investment for the new units assumed in each resource plan. The new unit additions comprise all of the capacity added for both resource plans.

In order to show that the cost categories that were addressed in these economic analyses are similar to those addressed in FPL's recent Need filings (with the exception of the transmission loss costs as mentioned above), Exhibit SRS-6 presents the economic evaluation results for the two resource plans for one fuel cost and environmental compliance cost scenario, the High Gas Cost Env I scenario, 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.

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

A. The environmental compliance costs were captured in the economic analyses through four 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.) 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 System Variable Costs for that scenario.

Q. What conclusions can be drawn from these results shown in Exhibit SRS-6?

A. It is important to remember that the results shown in Exhibit SRS-6 provide a comparison of the costs for the two resource plans under only one of the 9 fuel cost and environmental compliance cost scenarios, the High Gas Cost Env I scenario.

Exhibit SRS-6 shows that the Plan with Nuclear Uprates is approximately $612 million CPVRR less expensive than is the Plan without Nuclear Uprates for this scenario.

Although these results are valid for only one of the 9 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 8 scenarios.

The first such result is that the Plan with Nuclear Uprates has higher fixed costs and lower variable costs than does the Plan without Nuclear Uprates. The higher fixed costs are expected due to the relatively higher capital costs associated with the nuclear uprates. FPL witness Hale's testimony discusses the capital costs associated with the nuclear capacity uprates. The lower variable costs are also expected due to the fact that the additional 414 MW of low cost nuclear energy annually displaces a significant amount of higher priced fossil fuel-based energy and, due to the fact that nuclear energy generation results in no CO_2 emissions, results in lower system environmental compliance costs.

The second such result is that the System Fixed Costs for a specific plan 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 System Fixed Costs shown in Exhibit SRS-6 for the two resource plans will remain unchanged for all 9 fuel cost and environmental compliance cost scenarios while the System Variable Costs will change from one scenario to another.

Q. Please explain the nature of the Transmission System costs that are included in the resource plans.

A. Specific transmission capital costs associated with the nuclear capacity uprates are included in the Plan with Nuclear Uprates as indicated in FPL witness Hale's testimony. In regard to the CC units shown in the plans for 2011 – 2017, representative transmission interconnection costs are assumed, but no transmission integration capital costs were included in the analysis because no sites are known for the CC additions assumed in the resource plans. Similarly, for the filler units that appear in each of the plans for the 2021 – on time period, no transmission integration capital costs are assumed for the same reason. Finally, as previously discussed, the cost of losses for the two resource plans are not included, again because sites for these assumed future CC unit additions are not known.

Q. What were the results of the economic analyses in which all 9 of the fuel cost and environmental compliance cost scenarios were included?

A. Exhibit SRS-7 presents the total costs for the two resource plans for all 9 of these scenarios. In addition, the total cost differences between the two plans are also shown. The total cost results shown on this document for the High Gas Cost Env I scenario for the resource plans are the same as the total cost results presented for the resource plans in Exhibit SRS-6.

The total cost results shown on Exhibit SRS-7 for the remaining 8 scenarios have not been previously presented. However, by examining Exhibits SRS-6 and SRS-7 and considering that the System Fixed Costs shown on Exhibit SRS-6 do not change as the scenarios change, it is clear that all of the cost differences shown on Exhibit SRS-7 are due to the System Variable Cost category on Exhibit SRS-6. In other words, all of the differences are from changes in the fuel costs and/or environmental compliance costs.

In regard to the column titled Total Cost Difference in Exhibit SRS-7, a negative value indicates that the costs for the Plan with Nuclear Uprates are lower than those of the Plan without Nuclear Uprates. A positive value would indicate that the costs for the Plan with Nuclear Uprates are higher than those of the Plan without Nuclear Uprates.

Exhibit SRS-7 shows that the Plan with Nuclear Uprates has a lower CPVRR cost in 8 of the 9 scenarios of fuel cost forecasts and environmental compliance cost forecasts and that the economic advantage of the Plan with Nuclear Uprates in those 8 scenarios is significant. The Plan with Nuclear Uprates is projected to have higher CPVRR costs compared to the Plan without Nuclear Uprates only in the Low Gas Cost Env I scenario; i.e., only in the lone scenario with projected low natural gas costs and low environmental compliance costs. However, in that scenario, the total CPVRR cost for the Plan with Nuclear Uprates is at least $33 billion less expensive than the costs for either plan in any of the other 8 scenarios as is shown in the exhibit. Consequently, FPL's customers would still benefit in this scenario from the large amounts of gas on FPL's system and the forecasted low gas costs.

Exhibit SRS-7 provides a significant amount of cost and cost differential data for the two resource plans. In order to simplify this comparison of costs for the plans, the cost differentials for the plans that are shown in Exhibit SRS-7 are reorganized and presented again in matrix format in Exhibit SRS-8. The intent is to provide a somewhat more easily understood summary of the Total Cost Difference column results in Exhibit SRS-7, particularly as the results relate to the different fuel cost and environmental compliance cost forecasts.

Q. How would you summarize the information for each resource plan that is presented in Exhibit SRS-8?

A. First, it is again clear that the Plan with Nuclear Uprates is the lower cost plan in 8 of the 9 scenarios. In addition, this format shows that the CPVRR cost advantage of the Plan with Nuclear Uprates versus the Plan without Nuclear Uprates is greater on the left side of the matrix due to the higher natural gas cost forecasts on the left hand side. Also, the CPVRR cost advantage of the Plan with Nuclear Uprates versus the Plan without Nuclear Uprates is greater nearer the bottom of the matrix due to the higher environmental compliance costs in those matrix rows.

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

A. The nuclear capacity uprates are shown to be economical for FPL's system in 8 of the 9 scenarios. As presented in Exhibit SRS-8, the economic advantage of the uprates in those 8 scenarios ranges from $122 million CPVRR to $863 million CPVRR. In the lone scenario in which the Plan without Nuclear Uprates does not have the economic advantage, FPL's customers would still benefit from a total cost perspective compared to all other scenarios due to the low gas cost forecast that, in conjunction with the large amount of gas on FPL's system, drives this result.

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

A. No. There are two comparative aspects of the resource plans that have not been addressed in the economic analyses. These aspects involve the cost of losses and a periodic system concern in FPL's resource planning, a recurring imbalance between generation and demand in the Southeastern Florida region.

As previously discussed, the cost of losses was not included in the economic analyses due to lack of knowledge regarding where new CC units might be built in the 2011 – on time period. However, if the cost of losses were to be calculated, the fact that the Turkey Point site accounts for half of the uprated nuclear capacity would likely result in a advantage for the Plan with Nuclear Uprates in regard to the cost of losses due to Turkey Point's proximity to FPL's load center.

In addition, the fact that the Turkey Point site is located in the Southeastern Florida region means that its half of the total nuclear uprates capacity addition would have a positive impact on the recurring regional imbalance between generation and load in the Southeastern Florida region. As mentioned earlier, this imbalance has been addressed for a number of years with the addition of the Turkey Point Unit 5 (added in 2007) and the addition of WCEC Units 1 and 2 (to be added in 2009 and 2010, respectively). However, as the electrical load continues to grow, additional generation will subsequently need to be built in Southeastern Florida or additional transmission facilities that increase the ability to import power into the region will have to be built. The addition of approximately 200 MW in Southeastern Florida from the nuclear uprates at the Turkey Point site would certainly be helpful in addressing this imbalance.

Therefore, while these two qualitative advantages of the nuclear capacity uprates have not been quantified in the economic analyses, these advantages are real and would be expected to increase the economic advantage for the nuclear capacity uprates if a quantification of these advantages had been possible at this time.

Q. Has FPL projected the annualized base revenue requirements for the first 12 months of operation of each of the nuclear capacity uprates?

A. Yes. These base revenue requirements, also referred to as non-fuel costs, are presented in Exhibit SRS-9. The approximate non-fuel costs for the first 12 months for each of the capacity uprates at each of FPL's four existing nuclear units are, in the order the uprated units will go in-service, as follows:

- St. Lucie 1 = $59.8 million;
- Turkey Point 3 = $76.4 million;
- St. Lucie 2 = $61.8 million; and,
- Turkey Point 4 = $72.9 million.

These cost projections are based on the in-service dates, the in-service costs, and the financial/economic assumptions used in the economic analysis previously discussed. If the actual values are different for one or more of these assumptions, then the values projected in Exhibit SRS-9 may also change.

Q. What is the approximate magnitude of the impacts to FPL's customers' bills that can be expected from the nuclear uprates?

A. Monthly bills for FPL's customers can be expected to increase in years immediately preceding the in-service dates of the uprates as capital costs are recovered, and in the initial years after the uprates are completed because the largest annual amounts of the capital costs associated with the uprates that are recovered in those years are only partially offset by system fuel and environmental compliance cost savings. In later years, as the annual capital cost recovery amounts decline due to depreciation and the annual fuel and environmental compliance cost savings are expected to increase as these costs rise, the projected increased bill amounts will steadily decrease and then turn into bill savings.

For the years of 2009 – 2013, an approximate customer bill impact has been calculated for one of the scenarios and is presented in Exhibit SRS-10. The calculation is based on a system average rate differential for each year. The difference in the annual revenue requirements between the Plan with Nuclear Uprates and the Plan without Nuclear Uprates is calculated first. Then this annual revenue requirement differential is divided by the projected annual sales amount to develop a system average rate differential for each year. Finally, this system average rate differential is multiplied by 1,000 kwh to develop an approximate customer bill impact between the two plans.

As shown in Exhibit SRS-10 the results of that calculation for a 1,000 kwh bill are as follows are: $0.34 for 2009, $1.79 for 2010, $1.73 for 2011, $1.60 for 2012, and $0.21 for 2013.

VIII. Results of the System Non-Economic 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 the resource plans for the 2011 - 2013 time period; i.e., a system fuel mix projection. This three-year time frame was chosen because it addresses the time period starting when the first nuclear capacity uprate is assumed to come in-service (2011) through the first year that all of the nuclear capacity uprates are in-service for a full year (2013).

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 both resource plan for two scenarios, High Gas Cost Env III and Low Gas Cost Env I, selected to represent a range of fuel cost and environmental compliance cost forecast scenarios.

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

A. Exhibit SRS-11 presents the annual projection for 2011 - 2013 of the percentage of energy produced by coal/petroleum coke, natural gas, oil, nuclear, and other for the resource plans for the two scenarios mentioned above.

As shown in Exhibit SRS-11, the Plan with Nuclear Uprates holds a meaningful advantage in regard to fuel diversity compared to the Plan without Nuclear Uprates. When looking at the results for the High Gas Cost Env III scenario for the year 2013, it is projected that the Plan with Nuclear Uprates will result in FPL's system supplying approximately 19% of its energy with nuclear and 65% with natural gas. By comparison, it is projected that the Plan without Nuclear Uprates will result in FPL's system supplying only 17% of its energy with nuclear and 67% with natural gas. For the Low Gas Cost Env I scenario, the relative fuel mix percentages for the various fuels corresponding to the two resource plans are relatively unchanged.

An increase of 2% in nuclear's contribution to system annual fuel mix, and a corresponding decrease of 2% in natural gas' contribution, on a utility system the size of FPL's is definitely meaningful. This is more readily apparent when the difference is translated into terms of increased annual MWh supplied by the nuclear uprates, and the equivalent number of residential customers whose total annual energy usage could be supplied by the additional energy output from the nuclear uprates.

For 2013, the first full year in which all four uprates are in-service, the Plan with Nuclear Uprates will provide an increase of approximately 3.23 million MWh from nuclear compared to the Plan without Nuclear Uprates. Taking into account that FPL's average residential customer is projected to use approximately 15,200 kwh in 2013, the increased nuclear energy generation from the uprates would serve the total electricity needs of about 213,000 residential customers in 2013.

Therefore, the Plan with Nuclear Uprates is projected to have a meaningful fuel diversity advantage over the Plan without Nuclear Uprates.

Q. How were the effects of the two plans on FPL system emissions of CO2 evaluated?

A. The effects of the two resource plans on FPL's projected CO2 emission levels were evaluated by projecting the annual CO2 emission levels for the resource plans for the 2013 – 2043 time period. This time period addresses the year in which all of the nuclear capacity uprates are in-service for a full year (2013) through the year in which the last of the current operating licenses for FPL's existing nuclear units ends (2043).

Q. What were the results of the CO2 emission analysis?

A. The results of this analysis are presented in Exhibit SRS-12 which show that the cumulative total CO2 emission reduction from the nuclear uprates is significant, approximately 27 million tons. The cumulative values are calculated by first determining the annual amount by which FPL's system CO2 emissions will be lower with the Plan with Nuclear Uprates, then summing these annual emission reductions to develop cumulative reduction values by year. The Plan with Nuclear Uprates is projected to have lower system CO2 emissions than the Plan without Nuclear Uprates due to the fact that the increased capacity from the existing nuclear power plants result in zero CO2 emissions.

The results presented in the exhibit show annual CO2 emission reductions from the uprates of the four nuclear units to be slightly more than 1 million tons. This trend continues until approximately 2032 when the first of the operating licenses for FPL's existing nuclear units ends. Starting in that year the annual CO2 emission reductions from the uprates begin to decline from this level by approximately 25% starting in each year in which another nuclear unit's operating license ends. The last of these current operating licenses is scheduled to end in 2043. As previously mentioned, the cumulative total CO2 emission reduction from the nuclear uprates is approximately 27 million tons.

Q. Please summarize the results of the non-economic analyses of the two plans.

A. In regard to system fuel diversity, the Plan with Nuclear Uprates is projected to have a meaningful advantage over the Plan without Nuclear Uprates by increasing the contribution of nuclear energy to FPL's system fuel mix by approximately 2% while decreasing the contribution of natural gas by approximately the same percentage. This is equivalent to being able to serve approximately 213,000 residential customers' total electricity needs in 2013 just from the increased nuclear energy supplied by the uprates. In regard to system CO2 emissions, the Plan with Nuclear Uprates is projected to achieve a cumulative reduction in FPL system CO2 emissions of approximately 27 million tons compared to the Plan without Nuclear Uprates through the currently projected license terms of the nuclear units.

IX. Adverse Consequences of Not Approving the Nuclear Capacity Uprates

Q. Would there be adverse consequences if a Need Determination for the nuclear capacity uprates was not approved?

A. Yes. If FPL's request for a Need Determination for the nuclear capacity uprates is not approved, there would be adverse consequences as discussed in the previous sections. These adverse consequences include a high likelihood of higher system costs (projected for 8 of 9 scenarios), plus less system fuel diversity and higher CO2 emissions.

Q. Do the nuclear capacity uprates represent a unique opportunity to enhance FPL's system fuel diversity and lower system CO2 emissions?

A. Yes. The opportunity to increase the capacity of FPL's four existing nuclear units through these uprates is a unique circumstance to significantly increase nuclear capacity, thus increasing the percentage of annual energy produced by nuclear energy and lowering system CO2 emissions. No new sites are required for this additional nuclear capacity and the permitting time is minimal compared to a new nuclear unit. Therefore, an additional nuclear energy contribution to FPL's system can be accomplished much sooner through the capacity uprate approach than through the new nuclear generating unit approach.

X. Conclusions

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

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

1) The nuclear capacity uprates are the lowest cost alternative for FPL's system and its customers in the majority (8 out of 9) of the fuel cost and environmental compliance cost scenarios. In these 8 scenarios, the addition of the uprates resulted in lower CPVRR costs ranging from $122 million to $863 million. This economic advantage is from a combination of system fuel savings and capacity deferral. The only

scenario in which the nuclear uprates do not have an economic advantage is the lone scenario that features both a low gas cost forecast and a low environmental compliance cost forecast. However, in that scenario, the total CPVRR cost for the Plan with Nuclear Uprates is at least $33 billion less expensive than the costs for either plan in any of the other 8 scenarios. Consequently, FPL's customers would still benefit in this scenario from the large amounts of gas on FPL's system and the forecasted low gas costs.

2) The Plan with Nuclear Uprates has a meaningful advantage in regard to system fuel diversity compared to the Plan without Nuclear Uprates. For 2013, the first year in which the nuclear uprates for all four existing nuclear units will be in effect for a full year, FPL's system is projected to be 2% more reliant upon nuclear fuel and 2% less dependent upon natural gas than would be the case without the uprates. This equates to the total annual energy consumption in 2013 of approximately 213,000 residential customers being met solely by the increased nuclear energy production from the uprates.

3) The Plan with Nuclear Uprates has a significant advantage in regard to lowering system CO2 emissions compared to the Plan without Nuclear Uprates. The cumulative CO2 emission reduction for FPL's system from the nuclear uprates through the currently projected license term of the nuclear units is projected to be approximately 27 million tons.

4) Nuclear capacity uprates offers a unique opportunity to bring additional nuclear capacity and energy to FPL's customers a number of years sooner than would be possible with a new nuclear generating unit.

Based on these four results from the analyses, my conclusion is that FPL's Need Determination petition should be approved because FPL's customers will benefit economically in regard both to fuel savings and from capacity deferral, and will also benefit from greater system fuel diversity and from lower CO2 emissions.

Q. Would your conclusion be the same if the in-service dates of the nuclear uprates were different from those used in the analyses?

A. Yes. The economic and non-economic advantages of the nuclear uprates as analyzed are significant and these uprates should benefit FPL's customers regardless of the actual in-service date.

Q. Does this conclude your testimony?

A. Yes.

Projection of FPL's 2007 - 2020 Capacity Needs
(without New FPL Generating Unit 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	2,562	25,932	23,435	2,034	21,401	4,531	21.2%	(251)
2010	24,589	2,205	26,794	24,003	2,146	21,857	4,937	22.6%	(566)
2011	24,589	2,255	26,844	24,612	2,264	22,348	4,496	20.1%	(26)
2012	24,589	2,193	26,782	25,115	2,388	22,727	4,055	17.8%	**490**
2013	24,589	2,193	26,782	25,590	2,516	23,074	3,708	16.1%	**907**
2014	24,589	2,193	26,782	26,100	2,651	23,449	3,333	14.2%	**1,357**
2015	24,589	2,193	26,782	26,772	2,790	23,982	2,800	11.7%	**1,996**
2016	24,589	882	25,471	27,410	2,910	24,500	971	4.0%	**3,929**
2017	24,589	882	25,471	28,079	3,030	25,049	422	1.7%	**4,588**
2018	24,589	882	25,471	28,737	3,150	25,587	-116	-0.5%	**5,233**
2019	24,589	882	25,471	29,391	3,270	26,121	-650	-2.5%	**5,874**
2020	24,589	882	25,471	30,091	3,390	26,701	-1,230	-4.6%	**6,570**

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	2,239	27,105	23,587	1,814	21,773	5,332	24.5%	(977)
2011	26,201	2,238	28,439	24,047	1,883	22,164	6,275	28.3%	(1,842)
2012	26,201	2,382	28,583	24,498	1,954	22,544	6,039	26.8%	(1,530)
2013	26,201	2,202	28,403	24,952	2,028	22,924	5,479	23.9%	(894)
2014	26,201	2,202	28,403	25,416	2,106	23,310	5,093	21.8%	(431)
2015	26,201	2,202	28,403	26,048	2,188	23,860	4,543	19.0%	**229**
2016	26,201	882	27,083	26,692	2,264	24,428	2,655	10.9%	**2,231**
2017	26,201	882	27,083	27,342	2,334	25,008	2,075	8.3%	**2,927**
2018	26,201	882	27,083	27,994	2,404	25,590	1,493	5.8%	**3,625**
2019	26,201	882	27,083	28,649	2,474	26,175	908	3.5%	**4,327**
2020	26,201	882	27,083	29,308	2,544	26,764	319	1.2%	**5,034**

* No new FPL generating unit additions after WCEC 1 in 2009 and WCEC 2 in 2010 are assumed to be added. 287 MW of renewable energy firm capacity purchases starting in the 2009 - 2012 time frame are assumed to be added.

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

Projected Incremental FPL DSM: 2006 - 2020

Year	DSM Projected by FPL (Summer MW at Generator) (1)
2006	1,491
2007	1,768
2008	1,908
2009	2,034
2010	2,146
2011	2,264
2012	2,388
2013	2,516
2014	2,651
2015	2,790
2016	2,910
2017	3,030
2018	3,150
2019	3,270
2020	3,390
Incremental DSM MW from 2006 through 2020 =	1,899
Incremental DSM MW from 2006 through 2013 =	1,025

Notes: (1) The DSM Summer MW shown are from column (5) in Exhibit SRS -1 and reflect projected DSM signups from 8/2006 through 8/2020. These values reflect FPL's DSM Goals through 2014 plus additional DSM through 2014 identified as cost-effective after the DSM Goals were established and for which Commission approval has been obtained. These values also include a projected continuation of DSM signups for 2015 - 2020.

Projection of FPL's 2007 - 2020 Capacity Needs: With Proposed Nuclear Capacity Uprates *

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	2,562	25,932	23,435	2,034	21,401	4,531	21.2%	(251)
2010	24,589	2,205	26,794	24,003	2,146	21,857	4,937	22.6%	(566)
2011	24,589	2,255	26,844	24,612	2,264	22,348	4,496	20.1%	(26)
2012	24,899	2,193	27,092	25,115	2,388	22,727	4,365	19.2%	**180**
2013	25,003	2,193	27,196	25,590	2,516	23,074	4,122	17.9%	**493**
2014	25,003	2,193	27,196	26,100	2,651	23,449	3,747	16.0%	**943**
2015	25,003	2,193	27,196	26,772	2,790	23,982	3,214	13.4%	**1,582**
2016	25,003	882	25,885	27,410	2,910	24,500	1,385	5.7%	**3,515**
2017	25,003	882	25,885	28,079	3,030	25,049	836	3.3%	**4,174**
2018	25,003	882	25,885	28,737	3,150	25,587	298	1.2%	**4,819**
2019	25,003	882	25,885	29,391	3,270	26,121	-236	-0.9%	**5,460**
2020	25,003	882	25,885	30,091	3,390	26,701	-816	-3.1%	**6,156**

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	2,239	27,105	23,587	1,814	21,773	5,332	24.5%	(977)
2011	26,201	2,238	28,439	24,047	1,883	22,164	6,275	28.3%	(1,842)
2012	26,304	2,382	28,686	24,498	1,954	22,544	6,142	27.2%	(1,633)
2013	26,615	2,202	28,817	24,952	2,028	22,924	5,893	25.7%	(1,308)
2014	26,615	2,202	28,817	25,416	2,106	23,310	5,507	23.6%	(845)
2015	26,615	2,202	28,817	26,048	2,188	23,860	4,957	20.8%	(185)
2016	26,615	882	27,497	26,692	2,264	24,428	3,069	12.6%	**1,817**
2017	26,615	882	27,497	27,342	2,334	25,008	2,489	10.0%	**2,513**
2018	26,615	882	27,497	27,994	2,404	25,590	1,907	7.5%	**3,211**
2019	26,615	882	27,497	28,649	2,474	26,175	1,322	5.1%	**3,913**
2020	26,615	882	27,497	29,308	2,544	26,764	733	2.7%	**4,620**

* This exhibit is identical to Exhibit SRS-1 except that 414 MW of the proposed nuclear uprates is assumed. Approximately 104 MW are added in December 2011, 103 MW in May 2012, 103 MW in June 2012, and 104 MW by December 2012.

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

The Two Resource Plans Utilized in the Analyses

Plan with Nuclear Uprates	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021 - 2040
- unit(s) added	3x1 CC	Nuclear Uprate (3 units) *	Nuclear Uprate (1 unit) *	(none)	3x1 CC	3x1 CC	2x1 CC	Turkey Point 6	(none)	Turkey Point 7	38 - 2x1 CC
- annual MW added	1,219	310	104	0	1,219	1,219	812	1,100	0	1,100	21,014
- permanent MW added	1,219	1,529	1,633	1,633	2,852	4,071	4,883	5,983	5,983	7,083	28,097
- Reserve Margin	25.6%	24.6%	23.1%	21.2%	23.6%	20.6%	21.2%	22.9%	20.4%	21.9%	(all meet criteria)

Plan without Nuclear Uprates	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021 - 2040
- unit(s) added	3x1 CC	(none)	(none)	3x1 CC	(none)	2 - 3x1 CC	(none)	Turkey Point 6	(none)	Turkey Point 7	38 - 2x1 CC
- annual MW added	1,219	0	0	1,219	0	2,438	0	1,100	0	1,100	21,014
- permanent MW added	1,219	1,219	1,219	2,438	2,438	4,876	4,876	5,976	5,976	7,076	28,090
- Reserve Margin	25.6%	23.2%	21.4%	24.6%	21.8%	23.9%	21.1%	22.9%	20.4%	21.9%	(all meet criteria)

Notes: - assumes extension of DSM implementation through 2020 at currently planned implementation rates for 2012 - 2014 time frame
- assumes extension of three expiring waste-to-energy purchases and addition of three renewable energy capacity purchases totaling 287 MW
- assumes no peak load or annual energy growth after 2040

* One of the four nuclear uprates is scheduled to occur in Dec 2011, one in May 2012, one in June 2012, and one in Dec 2012. Because the 2011 uprate will occur after the Summer of 2011, for reserve margin calculation purposes the first three uprates are accounted for starting with the 2012 Summer reserve margin calculation. The fourth uprate is accounted for starting with the 2013 Summer reserve margin calculation.

Assumptions Used for the Analyses

Financial and Economic Assumptions

I. FPL Capital Structure, Discount Rate, and AFUDC Rate:

a) Projected Capitalization Ratios and Projected Cost of Capital:

Component	Ratio	Cost
Debt	44.20%	6.43%
Preferred	0%	0%
Equity	55.80%	11.75%

b) Projected Discount Rate = 8.40 % for generation costs and 8.30% for all other costs.

c) Projected AFUDC Rates

Year	Rate (%)
2007	7.42
2008	8.03
2009	8.17
2010	8.19
2011	8.20
2012 and beyond	8.19

d) Rate used for recovery of nuclear unit (pre-tax AFUDC) = 11.04%

II. Tax Assumptions:

a) Composite Effective Income Tax Rate (Federal and State tax rates adjusted for federal production tax credits for each unit) =
   35.100% for generation facilities
   38.575% for transmission facilities

b) Combined Cycle Book Life = 25 years

c) Combined Cycle Tax Depreciation Life = 20 years

d) Transmission Book Life = 40 years

e) Transmission Tax Depreciation Life = 15 years

III. General Inflation Rate = 2.5%

Assumptions Used for the Analyses

FPL's New Generating Unit Options (Non-Nuclear)

	Unit 1 3 x 1 CC	Unit 1 2 x 1 CC	Unit 1 2 x 1 CC
In-service year	2011	2017	2021
All costs are shown in in-service year $s	G Moderate Duct Fired Greenfield	G Moderate Duct Fired Greenfield	7FA Moderate Duct Fired Greenfield
I. Construction Costs ($1,000)			
Total Direct Cost	$686,572	$613,160	$457,804
Total Indirect Cost	$104,862	$93,446	$103,147
Total Other Cost(Transmission Interconnection)	$26,492	$23,042	$24,021
Grand Total Cost (In Service Year)	$817,925	$729,648	$584,971
II. Plant Characteristics (Unit Average)			
Net Sum 95FCapability (mw) - Base	1115	743	492
Net Win 35F Capability (mw) - Base	1246	831	543
Heat Rate btu/kwh 75F100% -Base	6,582	6,582	6,885
Duct Firing-Incremental from Base Sum MW 95F	104	69	48
Duct Firing-Incremental from Base Win MW 35F	89	59	47
Duct Firing-Incremental from Base Ann Avg Heat Rate 75F	8,770	8,770	8,620
Peak Firing- Incremental from Base Sum MW 95F	0	0	13
Peak Firing- Incremental from Base Win MW 35F	0	0	0
Peak Firing- Incremental from Base Ann Avg Heat Rate 75F	n/a	n/a	5,500
Annual Availability	96.8%	96.8%	97.0%
Ramp Rate (MW/Minute)	30	30	20
Minimum Load	320	320	180
III. Operation Costs			
Fixed O&M ($/kw-yr)(Summer Peak Output)	4.4	6.5	10.6
Variable (excl. fuel) ($/mwh) (Summer Peak Output @ 85% CF)	0.7	0.8	0.9
Capital Replace ($/kw-yr)(Summer Peak Output)	10.8	12.1	15.8
IV. Emission Rates			
NOx Emission Rates (lb/mmbtu)	0.010	0.010	0.010
SO2 Emission Rates (lb/mmbtu)	0.006	0.006	0.006
CO2 (lb/mmbtu)	119	119	119
Mecury, Hg (lb/Tbtu) (T=trillion)	0.000	0.000	0.000
V. Spending Curves (1,000) $			
Year 5	$1,656	$1,536	$1,272
Year 4	$56,736	$50,563	$41,259
Year 3	$469,672	$418,972	$342,364
Year 2	$222,529	$198,541	$162,209
Year 1	$67,333	$60,036	$49,171

Economic Analysis Results for One Fuel and Environmental Compliance Cost Scenario:

(millions, CPVRR, 2007$, 2007 - 2043)

Fuel Cost Forecast = **High Gas Cost**

Environmental Compliance Cost Forecast = **Env I**

	(1)	(2)	(3) = (1) + (2)	(4)
	System Costs			**Difference from Lowest Cost Plan**
Resource Plan	**Fixed Costs ***	**Variable Costs ****	**Total Costs**	
Plan with Nuclear Uprates	19,045	165,108	184,154	0
Plan without Nuclear Uprates	17,959	166,815	184,774	621

* System fixed costs include: capital, capacity payments, fixed O&M, capital replacement, and firm gas transportation.

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

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

(millions, CPVRR, 2007$, 2007 - 2043)

(1)	(2)	(3)	(4)	(5) = (3) - (4)
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans		Total Cost Difference Plan with Nuclear Uprates minus Plan without Nuclear Uprates
		Plan with Nuclear Uprates	Plan without Nuclear Uprates	
High Gas Cost	Env I	184,154	184,774	(621)
High Gas Cost	Env II	192,964	193,705	(740)
High Gas Cost	Env III	199,694	200,486	(792)
High Gas Cost	Env IV	206,651	207,523	(871)
Medium Gas Cost	Env I	142,281	142,412	(130)
Medium Gas Cost	Env II	151,007	151,259	(251)
Medium Gas Cost	Env III	157,664	157,961	(297)
Medium Gas Cost	Env IV	164,494	164,865	(370)
Low Gas Cost	Env I	108,803	108,498	305

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

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

Plan with Nuclear Uprates - Plan without Nuclear Uprates

Total Cost Differentials
(millions, CPVRR, 2007$, 2007 - 2043)

Fuel Cost Forecasts

		High Gas Cost	Medium Gas Cost	Low Gas Cost
Environmental	Env I	(621)	(130)	305
Compliance	Env II	(740)	(251)	
Cost	Env III	(792)	(297)	
Forecast	Env IV	(871)	(370)	

Notes: A negative value indicates that the Plan with Nuclear Uprates is less expensive than the Plan without Nuclear Uprates. Conversely, a positive value indicates that the Plan with Nuclear Uprates is more expensive than the Plan without Nuclear Uprates.

Economic Analysis Results: Projection of Nuclear Uprates
Non-Fuel Costs for the First 12 Months of Operation

1) Assumptions: All cost values are for the full year and are in Nominal $, millions

Unit:	St. Lucie 1	Turkey Point 3	St. Lucie 2	Turkey Point 4
Uprate In-Service Month/Year:	12/2011	5/2012	6/2012	12/2012
Number of 1st 12 Months in 2nd Year:	11	4	5	11
Year:				
2011	5.1	---	---	---
2012	59.7	50.9	36.5	6.2
2013	---	76.4	60.6	72.8

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

Year:				
2011	5.1	---	---	---
2012	54.7	50.9	36.5	6.2
2013	---	25.5	25.3	66.7
	-------------	-------------	-------------	-------------
Total Non-Fuel Costs for the First 12 Months of Operation =	59.8	76.4	61.8	72.9

Notes:

1) The only non-fuel costs associated with the nuclear uprates are capital costs. Consequently, the values shown above are all capital costs.
2) For purposes of this calculation, the uprated units are assumed to go in-service on the first day of the month shown.
3) All cost projections are dependent upon the assumptions used in the calculations assuming in-service dates, annual costs incurred, etc. and are subject to change as assumptions change.
4) The transmission costs associated with the uprates at the Turkey Point and St. Lucie sites are assumed for purposes of this calculation to be assigned 100% to the uprate at that site with the earliest in-service date.

Economic Analysis Results: Projection of Approximate Bill Impacts with Nuclear Uprates 2009 - 2013

Scenario: High Gas Cost Env I

Year	Plan with Nuclear Uprates Annual Total Revenue Requirements ($millions, Nominal $)	Plan without Nuclear Uprates Annual Total Revenue Requirements ($millions, Nominal $)	Differential in Annual Total Revenue Requirements ($millions, Nominal $)	Projected Total Sales After DSM (GWh at the meter)	Differential in System Average Electric Rates (cents/kwh)	Differential in Customer Bill of 1,000 kwh ($)
	(1)	(2)	(3) = (1)-(2)	(4)	(5) = ((3)x1,000,000x100) / ((4)x1,000,000)	(6) = ((5)x1,000) / 100
-------	-------	-------	-------	-------	-------	-------
2009	8,316	8,287	30	116,870	$0.03	$0.25
2010	8,680	8,464	216	120,715	$0.18	$1.79
2011	8,507	8,292	215	124,562	$0.17	$1.73
2012	8,401	8,196	206	128,243	$0.16	$1.60
2013	8,874	8,846	28	131,170	$0.02	$0.21

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1), (2), and (3) are total system revenue requirements and include all costs: capital, system fuel (including the cost of the extended outages in the Plan with Nuclear Uprates), etc.

Non-Economic Analysis Results: FPL System Fuel Mix Projections by Plan

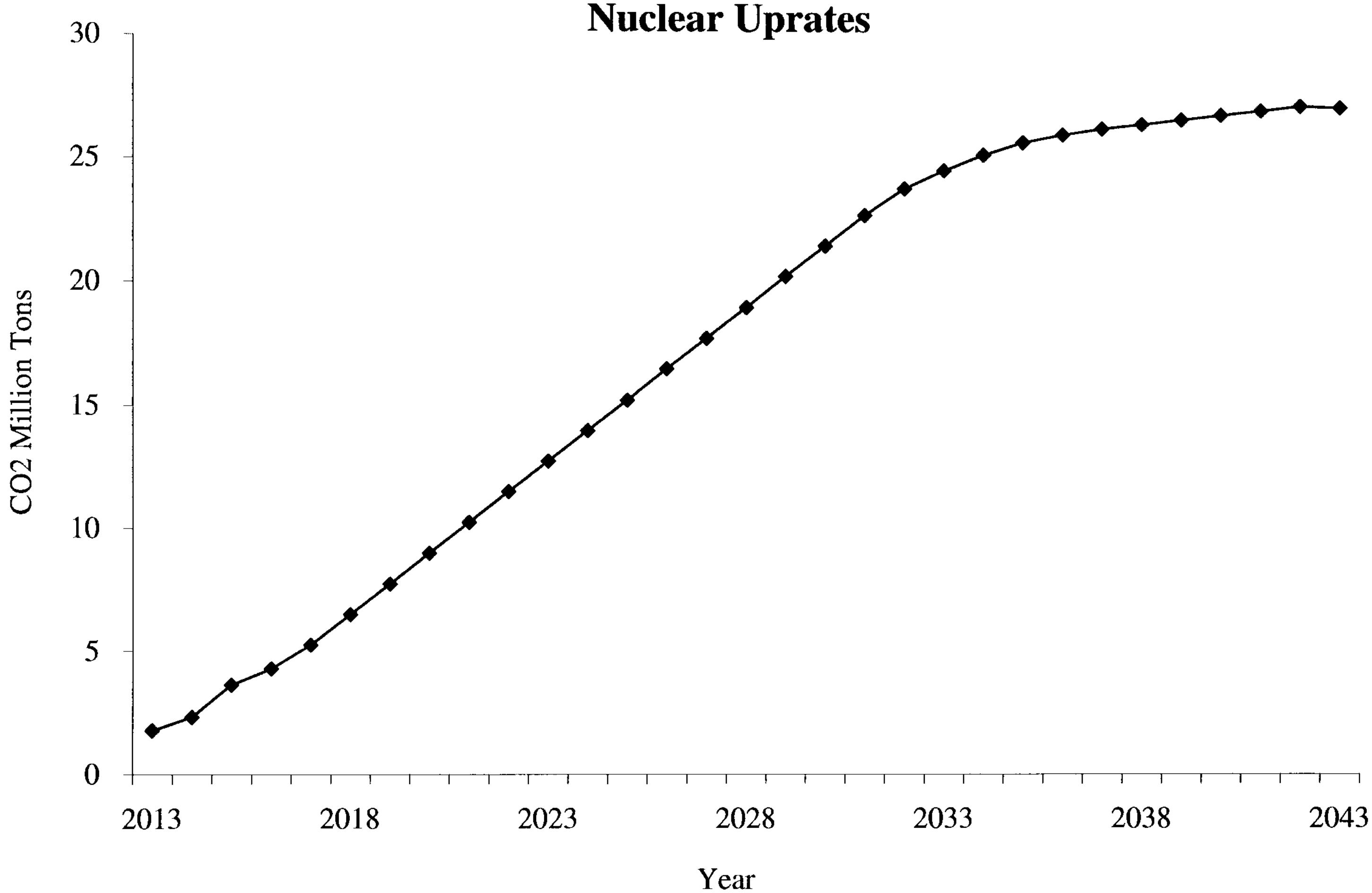
Scenario: High Gas Cost Env III

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Plan with Nuclear Uprates					Plan without Nuclear Uprates				
Year	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)
2011	11.9%	67.1%	1.6%	17.3%	2.1%	11.9%	64.5%	3.4%	18.2%	2.1%
2012	11.5%	66.2%	1.5%	18.1%	2.7%	11.5%	66.3%	2.1%	17.4%	2.7%
2013	11.2%	65.2%	1.7%	19.2%	2.8%	11.2%	66.8%	2.3%	16.9%	2.8%

Scenario: Low Gas Cost Env I

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Plan with Nuclear Uprates					Plan without Nuclear Uprates				
Year	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)
2011	11.9%	67.1%	1.6%	17.3%	2.1%	11.9%	64.4%	3.5%	18.2%	2.1%
2012	11.5%	66.1%	1.6%	18.1%	2.7%	11.5%	66.1%	2.2%	17.4%	2.7%
2013	11.2%	65.1%	1.8%	19.2%	2.8%	11.2%	66.7%	2.4%	16.9%	2.8%

Non-Economic Analysis Results: Cumulative FPL System CO2 Emission Reductions from Nuclear Uprates



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Non-Economic Anlaysis results:
Cumulative FPL System CO2
Emission Reductions from
Nuclear Uprates
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