SCANNED

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 040029-EG
FLORIDA POWER & LIGHT COMPANY

IN RE: FLORIDA POWER & LIGHT COMPANY'S PETITION FOR APPROVAL OF NUMERIC CONSERVATION GOALS

DIRECT TESTIMONY & EXHIBIT OF:

STEVEN R. SIM

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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JUNE 1, 2004

Q. Please state your name and business address.

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

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

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

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

A. I supervise a group that is responsible for determining the magnitude and timing of FPL's future resource needs, analyzing supply and demand side management (DSM) options which could potentially meet these future needs, and developing FPL's integrated resource plan (IRP) with which FPL intends to meet these needs.

Q. Please describe your education and professional experience.

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

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

In 1979 I joined FPL, and from then until 1985, I worked first in the Marketing Department and then in the Energy Management Research Department. My responsibilities during this time included the development and monitoring of numerous DSM programs. In 1985 I began working in FPL's Load Management Department as Supervisor of Planning. My responsibilities there involved design of FPL's load management programs, cost-effectiveness analyses and monitoring of these programs, and the integration of these programs with FPL's capacity resource plans.

In 1991 I joined my current department, then named the System Planning Department, as a Supervisor of Supply and Demand Analysis, where my responsibilities included the cost-effectiveness analyses of a variety of individual supply and DSM options. I assumed my present position in 1993.

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

A. The purpose of my testimony is to explain a number of the FPL system-related analyses that were conducted in determining the level of cost-effective DSM that FPL is now proposing as its DSM goals for 2005 through 2014.

Q. **How is your testimony structured?**

A. My testimony is presented in 4 parts. First, I briefly introduce FPL's basic IRP approach to evaluating resource options such as DSM and discuss several key planning assumptions that were used in FPL's IRP work during the first half of 2004 to determine the level of cost-effective DSM that FPL is now proposing as its new DSM Goals. In this section I introduce the "Supply Only" resource plan (i.e., a resource plan without incremental DSM beyond 2004) to which a resource plan containing incremental DSM will later be compared in the final determination of the cost-effectiveness of the incremental DSM. (Both the Supply Only resource plan, and the competing resource plan that will contain incremental DSM, assume that the load reduction capability from all load management participants signed up through 2004 will continue. In addition, the load forecast used in creating these resource plans accounts for the impacts of all previously signed up conservation participants.)

Second, I discuss the analyses performed to determine which individual DSM measures (or programs) were potentially cost-effective for FPL to implement. The cost-effectiveness screening of individual DSM options is addressed in this section. (Mr. Brandt's testimony also addresses portions of this work.) The analyses performed to evaluate the usable amount of incremental load control on FPL's system, and the results of those analyses, are also discussed.

Third, I discuss the development of a "With DSM" resource plan that contains the potentially cost-effective amount of incremental DSM. The Supply Only and With DSM resource plans are then compared in order to determine whether the projected amount of incremental DSM is truly cost-effective.

Fourth, the analyses conducted to determine FPL's proposed new DSM Goals are summarized.

Q. Are you sponsoring an exhibit?

A. Yes, the exhibit consists of the following 12 documents:

Document No. SRS-1: Overview of FPL's IRP Process

Document No.SRS-2: FPL's Resource Plan in its 2004 Ten-Year Power Plant Site Plan (with current DSM Goals)

Document No.SRS-3: Projected FPL Resource Needs Without Incremental DSM

Document No. SRS-4: The Supply Only Resource Plan for 2005 - 2014

Document No. SRS-5: Summary of Results of the Cost-Effectiveness Screening

Document No. SRS-6: Hypothetical Utility Peak Day Load Shape

Document No. SRS-7: Representative Effect of Implementing 100 MW of Load Control on the Hypothetical Utility Peak Day Load Shape

Document No. SRS-8: Representative Effect of Implementing 200 MW of Load Control on the Hypothetical Utility Peak Day Load Shape

Document No. SRS-9: Calculation of System Average Levelized Rate for the Supply Only Resource Plan

Document No. SRS-10: Projected FPL Resource Needs If Needs Are Met Solely by DSM

Document No. SRS-11: The With DSM Resource Plan for 2005 - 2014

Document No. SRS-12: Calculation of System Average Levelized Rate for the With DSM Resource Plan

I. FPL's Planning Approach, Key Planning Assumptions, and the Development of the Supply Only Resource Plan

Q. Please briefly describe FPL's approach to evaluating the role of DSM in meeting future resource needs.

A. FPL utilized its basic IRP process to analyze what role DSM should play in its resource plan. This basic process has been well-documented in each of the last several Ten-Year Power Plant Site Plans (Site Plan) filed with the Florida Public Service Commission (Commission). A copy of the discussion of the IRP process that appeared in the 2004 Site Plan is presented in Document No. SRS-1, and FPL's resource plan that was presented in its 2004 Site Plan is shown in Document No. SRS-2. This resource plan incorporates FPL's current DSM Goals for the years 2000 through 2009 that were approved by the Commission in 1999.

FPL believes that an IRP approach is the best way to determine how much of any resource option, supply or DSM, should be included in FPL's resource plan, because it allows options to compete on an equitable basis in economic analyses to earn a place in the resource plan.

Q. Did the 2004 IRP work differ from FPL's IRP work conducted in previous years?

A. Yes, but only in regard to two starting assumptions. The same basic IRP process has been used by FPL since late 1993 for all of FPL's resource planning work, including work performed for the previous two DSM Goals dockets. During the last few years, FPL's IRP work assumed that the level of DSM from 2000 through 2009 called for in FPL's current DSM goals was a "given" in the annual planning work. Thus, DSM did not have to compete for a place in the resource plan for all years through 2009, since DSM's role in the resource plan had been established in the previous Goals docket. However, since the purpose of this docket is to reset DSM goals for the years 2005 through 2014, it was not appropriate to continue to view predetermined DSM levels for the years 2005 through 2009, i.e., the remaining years covered by FPL's current DSM Goals, as a "given".

Consequently, one assumption of the IRP work performed in early 2004 to address the cost-effective level of incremental DSM was that only currently planned DSM additions through 2004 were a given and that <u>no</u> incremental DSM would be viewed as a given beyond January

1, 2005. Therefore, DSM would have to compete to earn a role for 2005 and beyond in FPL's resource plan.

Q. **What was the other planning assumption that differed from those utilized in IRP work conducted in previous years?**

A. The other assumption involved near-term new generating units that were considered as "givens" in FPL's 2004 resource planning work for the DSM Goals docket. The generating units that were considered "givens" in the most recent resource planning work (and that are discussed in Document No. SRS-2) are the following:

- a new 1,107 MW (Summer) combined cycle (CC) unit, Manatee Unit No. 3, at FPL's existing Manatee plant site that will come in-service in June, 2005;
- the conversion of two combustion turbine (CT) units at FPL's existing Martin plant site into a 1,107 MW (Summer) four-CT based CC unit, Martin Unit No. 8, with the addition of two additional CT's, four heat recovery steam generators, and a steam boiler. The new CC unit will also come in-service in June, 2005; and,
- a new 1,144 MW (Summer) CC unit, Turkey Point Unit No. 5, at FPL's existing Turkey Point plant site that is planned to come in-service in June, 2007.

FPL considered these generating units to be "givens" in its resource planning work to determine the cost-effective amount of incremental DSM. Both of the 2005 CC units are already under construction. The third generating unit, the proposed new 1,144 MW CC unit for 2007, is too large, and is planned to come in-service too early, to be avoided or deferred by incremental DSM starting in 2005.

As stated above, the first two units considered as "givens", Manatee Unit No. 3 and Martin Unit No. 8, are under construction. The Commission granted Determinations of Need for the two units, and both have received Site Certification Approval from the Florida Department of Environmental Protection (DEP) with concurrence by the Florida Electrical Power Plant Siting Board.

In regard to the third unit mentioned above as a "given", Turkey Point Unit No. 5, FPL filed a petition with the Commission on March 8, 2004 for approval of a Determination of Need for this unit with the Commission, and the Commission has scheduled a hearing on the petition in early June 2004. FPL has also filed for Site Certification Approval with the DEP, and a decision on this filing is anticipated in early 2005.

Q. What are the potential effects of the two planning assumptions discussed above on the role of DSM in FPL's resource plan?

A. The effects of these two assumptions vary in terms of the magnitude and timing of DSM's potential role in FPL's resource plan. The first assumption – that incremental DSM from January 1, 2005 through 2009 would be removed as a "given" from the resource planning work – <u>increases</u> FPL's resource needs for all years starting in 2005 and moves those resource needs closer to the present. The effect of removing DSM previously projected (due to FPL's current DSM Goals) to be added from 2005 through 2009 creates a "hole" in the resource plan in that time period. This affords the incremental DSM now being examined an opportunity to at least refill that hole and, perhaps, play an even greater role in those years.

The second assumption – that three new CC units, each of approximately 1,100 MW of capacity, are planned to be added to FPL's system, two in 2005 and one in 2007 – has the opposite effect. These additions <u>lower</u> FPL's resource needs from 2005-on and decrease the opportunity for incremental DSM to earn a role in FPL's resource plan.

Q. Describe the development of the Supply Only Resource Plan.

A. FPL used the resource plan for 2004 through 2013 presented first in its 2004 Site Plan, and again in Document No. SRS-2, as its "starting point" plan. Then, two changes were made to this starting point plan. First, the incremental DSM included in the starting point plan from January 1, 2005 through 2009 was removed. This resulted in a total of approximately 385 MW (Summer, at the generator) of planned DSM demand reduction being removed. As previously mentioned, this both increased FPL's resource needs and accelerated those needs.

Second, the generating unit additions in the plan for 2008-on were removed. As previously discussed, the two new generating units for 2005, and the new generating unit for 2007, remained in place.

These two changes allowed FPL to project what its resource needs would then be for the 2005 through 2014 time period without these DSM and generating unit resources. Document No. SRS-3 shows those projected resource needs in terms of MW needed with the two changes discussed above. The calculations shown in this document assume that only supply options – purchases and/or new construction options – would be used to meet those projected resource needs.

Using these supply resource need projections, a new Supply Only resource plan was developed that met the increased and accelerated needs. FPL used its Electric Generation Expansion Analysis System (EGEAS) model to develop this resource plan. The resulting Supply

Only resource plan is presented in Document No. SRS-4 along with the associated annual Summer reserve margin values. This resource plan meets FPL's dual reliability criteria of a minimum reserve margin of 20% (with one year falling only slightly below this value) and a maximum annual Loss-of-Load-Probability (LOLP) value of 0.10.

Q. How does this Supply Only resource plan differ from the resource plan presented in FPL's 2004 Site Plan?

A. A comparison of Document Nos. SRS-2 and SRS-4 show that there are three basic differences. First, there is an increased resource need of approximately 170 MW in 2007 that is assumed to be met by a new one-year, 170 MW purchase for that year. Second, the two CT units previously shown to be added in 2008 have been increased to four CT units in that year. Third, the addition of 2 new CC units, one each in 2011 and 2013, that was previously shown has been changed to three new CC units, one each in 2010, 2012, and 2014. These changes are needed to meet the greater and accelerated resource needs that are a result of removing the previously projected DSM additions for 2005 through 2009.

Q. Why is the Supply Only resource plan needed to determine the cost-effective amount of incremental DSM?

A. The Supply Only resource plan is used in three ways in this work. The first way it is used is in assisting to set assumptions for the cost-effectiveness screening of individual DSM measures to determine which DSM measures are potentially cost-effective. The second way it is used is in serving as the starting point in developing a With DSM resource plan once it is known which DSM measures are potentially cost-effective and the achievable potential of each measure. The third way in which this plan is used is in serving as a "standard" to which the With DSM resource plan is compared by analyzing the impact each plan has on FPL's projected system average electric rates. If FPL's projected system average electric rates are lower with the With DSM resource plan than with the Supply Only resource plan, then the amount of incremental DSM included in the With DSM resource plan is truly cost-effective.

II. Cost-Effectiveness Screening of DSM Measures and the Determination of Usable Amounts of Incremental Load Control

Q. What is the purpose of the cost-effectiveness screening of individual DSM measures?

A. To construct a portfolio of DSM measures that includes all of the cost-effective DSM available to FPL to help it meet its resource needs in the 2005 through 2014 time period, it is necessary to determine the following information for each DSM measure: (1) whether the measure is potentially cost-effective, and (2) the potential contribution of the measure over this time period. In performing the cost-effectiveness screening analyses, FPL uses both the Rate Impact Measure (RIM) test and the Participant test.

The cost-effectiveness screening first allows FPL to determine whether the individual measures are potentially cost-effective. Measures that do not pass this screening are not considered further. For those measures that do pass this screening, FPL can then determine the maximum incentive payment level for the measure that allows the measure to remain cost-effective. This maximum payment level to potential customers is then used to determine the size of the potential market for the measure that is achievable over the 2005 through 2014 time period.

Q. Please describe the cost-effectiveness screening process.

A. FPL's cost-effectiveness screening of individual DSM measures is carried out in four steps that utilize the Commission's approved cost-effectiveness methodology.

In the first step, which is carried out by the Resource Assessment and Planning Business Unit (RAP), a "stripped down" version of each individual DSM measure is analyzed versus the likely type of supply option the measure would have to displace to earn a role in the resource plan. (The likely type of supply option that was used in the screening analyses will be discussed later in my testimony.) This version of each DSM measure is considered "stripped down" because no cost information - no administrative costs or incentive payments - are included in this step of the analyses. The information supplied for the "stripped down" DSM measure includes all of the information needed to project the economic benefits of implementing the measure on FPL's system (i.e., the kw and kwh reductions per participant). The intent of this analysis step is to determine whether a DSM measure is potentially cost-effective when all of the measure's benefits are compared to <u>only</u> the revenue losses associated with the measure. Both the benefits and the revenue losses are determined on a long-term, net present value basis. DSM measures whose benefits do <u>not</u> exceed the revenue losses are considered to have failed this first step of the screening and are not considered further.

In the second step of the cost-effectiveness screening, the projected length of time that it takes a DSM option to "pay for itself," assuming no incentive payment is made by FPL to the participant, is determined. This is a question of how long it takes for the savings in a participant's bills to equal the participant's out-of-pocket costs for acquiring the measure. If this "payback" period is two years or less, FPL views the measure as one that is sufficiently attractive to potential participants that FPL's involvement in promoting the measure is not needed. Consequently, all measures that "survived" the first screening step, but which have a payback of two years or less, are not considered further. Mr. Brandt discusses this second step of the screening, which is carried out by the Product Management and Operations (PMO) Department, in more detail in his testimony.

In the third step of the cost-effectiveness screening, administrative costs are added for each surviving DSM measure, and the measure's cost-effectiveness is again determined by RAP. All DSM measures whose benefits do not exceed the sum of their administrative costs and revenue losses (but with no incentive payment yet assumed), are not considered further. The surviving DSM measures that pass this cost-effectiveness screening step are then carried forward to evaluate what incentive payment is applicable for each measure.

Q. What is the fourth and final step of the cost-effectiveness screening?

A. For the measures that survive the third cost-effectiveness screening step; i.e., measures whose benefits exceed the sum of administrative costs and revenue losses, this "net benefits" calculation defines the amount of incentive payment FPL can offer and still have the measure remain cost-effective. In other words, FPL can offer an incentive up to the amount where the cost of the incentive equals the net benefits amount. This becomes the maximum possible incentive for that measure.

In the fourth and final step, FPL determines what incentive, up to the maximum incentive amount, FPL can offer so that the measure passes both the RIM test and the Participant test. If such an incentive amount can be determined, then the measure has survived all of the screening steps and is deemed to be potentially cost-effective. However, if there is no incentive level that will allow the measure to pass both the RIM and Participant tests, then the measure is dropped from further consideration.

PMO then uses the selected incentive level for each surviving measure to develop projections of how many participants (or how many kw) the market potentially could provide for each year in the 2005 through 2014 time period. Mr. Brandt's testimony addresses this effort.

Q. In the cost-effectiveness screening, how did FPL determine the "likely supply option" that DSM might displace?

A. To perform the cost-effectiveness screening of DSM measures, it was necessary to first project the <u>type</u> of new generating units that would be added to FPL's system absent any incremental DSM and <u>when</u> those units would likely be added. The Supply Only resource plan shown in Document No. SRS-4 answers those two questions. This resource plan shows that the majority of the new generating options that FPL would add absent any incremental DSM after 2004 are CC units. Therefore, it was clear that incremental DSM would primarily be competing with CC capacity over the 2005 through 2014 time period.

When considering the size (approximately 1,100 MW) of the new CC units projected to be added, it was clear that if the potential achievable amount of cost-effective incremental DSM over the ten-year time period was similar to that determined during the last DSM Goals proceedings (approximately 765 MW Summer at the meter), then there would <u>not</u> be sufficient cost-effective DSM to <u>avoid</u> a generating unit of this size. Consequently, the benefits of incremental DSM would be derived from deferring the addition of these units. Also, again assuming that the amount of potentially achievable cost-effective DSM was similar to this 700 MW-plus level, there would likely be more than one deferral of these large generating units over the ten-year time period as seen from a comparison of the differences in the 2010 through 2014 CC additions between Document Nos. SRS-2 and SRS-4.

While the Commission's approved cost-effectiveness methodology can be used to determine the DSM benefits associated with deferring a single generating unit, it does not lend itself well to calculating the benefits of multiple unit deferrals. Therefore, in order to address the likely impact of incremental DSM from 2005 through 2014 for screening purposes, FPL chose to use an avoided unit approach that was representative of the expected multiple unit deferral pattern.

In order to determine how a single avoided unit approach might best represent the expected multiple unit deferral pattern, FPL took the Supply Only resource plan and added 10 years of hypothetical DSM MW with the amount of DSM for each year of the 2005 through 2009 time period matching the annual DSM additions in FPL's current DSM Goals for 2005 through 2009, then with a similar 5-year incremental DSM pattern being repeated for 2010 through 2014. The projected impact of this hypothetical amount of DSM on the Supply Only resource plan did result in a multiple unit deferral pattern. This deferral pattern appeared for many of the years from 2010 – on, which provided a reasonable approximation of having avoided a unit in 2010.

This observation, plus the fact that a 2010 avoided unit assumption would allow FPL to look at DSM costs over a 5-year signup period (2005 through 2009) covering half of the time period for which new DSM Goals are to be set, led FPL to use a 2010 avoided CC unit and the Commission's approved cost-effectiveness methodology in order to perform the economic screening of individual DSM measures.

DSM measures that survived this screening work were deemed to be potentially cost-effective. Later in the analyses, FPL would again use its EGEAS model to create a "With DSM" resource plan that included potentially cost-effective DSM and that could be compared to the Supply Only resource plan. This approach allowed DSM to be compared from a resource plan perspective from which a determination can be made if the incremental DSM is truly cost-effective.

Q. What were the results of the cost-effectiveness screenings of the individual DSM measures?

A. FPL's PMO department identified a total of 329 DSM measures for analysis. In examining these measures, it was determined that a number of them were "identical" in regard to their demand and energy reduction impacts, but different in their potential applications. For example, the same DSM measure may be applicable to both existing construction and to new construction. In other cases, the same measure may be applicable to existing construction or it could be evaluated as a Code Utility Evaluation (CUE) application. In either of these cases, the same measure was properly counted twice in the total count of 329 DSM measures.

However, in regard to the possible cost-effectiveness of these "identical" measures, since they possessed identical kw and kwh reduction characteristics, it was only necessary to evaluate one of the "identical" pair. Consequently, the list of 329 total measures was reduced to 224 DSM measures for the cost-effectiveness screening.

Of these 224 DSM measures submitted for analysis, 162 measures, in their "stripped down" mode, were found to be cost-effective in the first step of the screening process. Consequently, 62 measures were eliminated from further consideration at this point because their revenue losses exceeded their benefits.

In the second step of the cost-effectiveness screening, 23 measures that had survived the first step of the screening were eliminated after it was determined that the payback period for the measure was two years or less. At this point, 139 surviving measures remained.

The addition of administrative costs in the third step of the screening process eliminated another 29 measures. This resulted in 110 surviving measures for which the maximum incentive level was determined.

In the fourth and final screening step, 56 additional measures were eliminated when incentive levels that allowed the measure to pass both the RIM and Participant tests could not be found for those measures.

This left 54 DSM measures that survived the cost-effectiveness screening process. All but one of these 54 surviving measures were carried forward through the rest of the DSM Goals-setting analyses; one measure survived but the analyses had shown that only a $1 incentive payment was possible if the measure was to pass both the RIM and Participant tests. Since a $1 incentive payment would allow virtually no market potential for this measure, the measure was dropped from further consideration. The remaining 53 DSM measures were retained for the rest of the DSM Goals analyses. (Later, when FPL developed estimates of the achievable market potential for these remaining 53 measures, any "identical" measures associated with these 53 measures were included in the development of the market potential estimates.) Mr. Brandt's testimony also addresses these DSM screening analyses and provides more detail regarding both the participant pay back and incentive level determination steps.

Document No. SRS-5 provides a summary view of the results of the cost-effectiveness screening steps of the individual DSM measures. Mr. Brandt's testimony also discusses the DSM screening analyses and provides additional detail regarding the participant pay back and incentive level determination steps, plus provides detailed screening results for each of the individual measures evaluated.

Q. Did FPL perform additional analyses to determine the potential for DSM measures?

A. Yes. FPL conducted analyses that were directed at evaluating the potential contribution of incremental load control capacity on FPL's system. These analyses were a continuation of similar analyses FPL has conducted in the past. The objective of these analyses is to determine whether FPL is at, or near, what it terms a "physical limit" as to how much load control is "usable" on its system.

Q. Please explain this concept of a "physical limit" for load control on a utility system.

A. One way to demonstrate the concept is by visualizing the shape of a utility's peak day load and how the implementation of load control affects this load shape. To simplify matters, assume that a utility's peak day load shape resembles a normal distribution curve with the peak hour's load at the very top of the curve. Document No. SRS-6 presents such a peak day load shape for a hypothetical utility.

The objective of load control is to lower the peak load of the system when load control is implemented. When it is implemented, load control reduces the electrical load on the utility's system from the participating customers' equipment. Then, when load control implementation ends (or load control is "released"), the utility system typically experiences some short-term "payback" as pent-up demand for electricity from this equipment (particularly if the equipment is controlled by a thermostat such as is the case with air conditioners and water heaters) is now served.

To lower the system's peak load, a utility typically initiates load control prior to what its peak load hour would have been, and continues it for a time past what the peak load hour would have been, to ensure that the "payback" effect does not create a new, higher peak load. A result of load control's implementation is a "flattening" of the load shape for a period of time. An example of the effect of this typical implementation practice on a utility's peak day load shape is illustrated in Document No. SRS-7.

In Document No. SRS-7, load control is implemented for a period of time (for example, 3 hours) to achieve a desired 100 MW load reduction. Note that it is necessary to implement load control for this period of time to ensure that the load does not rise above the "w/ load control" line during the 3 hours (i.e., to really achieve the 100 MW demand reduction). In other words, load control must be implemented for a time period stretching from the left-hand side of the load curve to the right-hand side (which is a time span of 3 hours in this example) to achieve the desired 100 MW demand reduction.

The key point is that in order to achieve a given load reduction (i.e., a given drop down from the original peak hour load), it is necessary to implement and sustain load control for a specific number of hours (determined by the width across from the left-hand side of the load curve to the right-hand side).

Now assume the same utility wishes to implement load control to achieve double the demand reduction (200 MW). This means there is a greater drop down from the original peak hour load (from 100 MW to 200 MW), and a greater number of hours (i.e., the width across the load shape) for which the load control must be sustained (from 3 hours to 5 hours in this example). This is illustrated in Document No. SRS-8.

This brings us to the concept of a "physical limit" to how much load control makes sense for a utility system. Since load control must be sustained for a longer time period as the desired demand reduction gets greater, it is possible for the distance across the load shape simply to become too great a time period for the load control to be sustained. This is particularly true considering that most load control programs have tariff (or other) restrictions on the number of hours particular equipment can be controlled.

FPL considers the "physical limit" to load control on a utility system to be the point at which a desired increase in load reduction cannot be achieved due to the length of time the control must be sustained.

Note that this "limit" can be increased by either increasing the tariff limits of control time or by essentially operating load control in a "relay race" mode in which two participating customers now are required to sustain a duration of control longer than is possible with only one customer. For example, if it is necessary to sustain load control for 7 hours to achieve a desired reduction and the tariff limit control period is only 6 hours, it would be possible to have one participating customer "carry" the demand reduction for up to 6 hours and then have a second participating customer "carry" the demand reduction the rest of the time period until 7 hours are reached.

However, there are drawbacks to both of these "remedies". Participating customers will only remain on the program as long as control durations do not exceed a tolerance threshold. Thus, there are limitations to this "remedy" itself. Likewise, using two participants to achieve additional demand reduction when the previous level of reduction only required one participant means that the cost-effectiveness of this next reduction increment has been significantly reduced (i.e., approximately cut in half) since two participants must now be used to accomplish the demand reduction that could previously be achieved with the use of only one participant.

Q. Does the same physical limit to load control apply to every utility?

A. No. Although FPL believes there is a physical limit as to how much load control is usable on each utility system, this limit will vary from one utility system to the next. It is highly dependent upon peak day load shape. For example, FPL's Summer peak day load shape typically shows many more hours of high load than does FPL's Winter peak day. The Summer peak day load shape is thus <u>broader across</u> than the Winter peak day load shape (which is characterized by a "spike-like" appearance). All else equal, this means that FPL could utilize more MW of load control on a Winter peak day than on a Summer peak day simply because the demand reduction would have to be carried for fewer hours in Winter. In other words, there is a higher physical limit to Winter load control than to Summer load control for FPL.

Therefore, the amount of usable load control can even vary seasonally for the same utility. This physical limit of load control also varies from one utility to another depending upon the utilities' respective peak day load shapes, tariff restrictions on control duration, and the importance of Winter versus Summer peak loads in regard to resource planning.

Q. How does FPL analyze the physical limit of load control on its system?

A. The basic steps for FPL's analyses include the following:

1) Develop a 15-minute interval projection of a future peak day load shape. For example, develop such a projection for an August, 2009 peak day.

2) Input assumptions for demand reduction and payback on a per participant basis for all of the types of equipment controlled by the load control programs. FPL includes projections for its residential, small commercial, and large Commercial/Industrial load control programs in these analyses.

3) Input the current tariff restrictions and current level of load control participants for each of these load control programs.

4) Using linear programming techniques, seek to utilize as much of the current load control as possible in order to minimize the future peak day's highest hourly load as much as possible.

5) If 100% of the current load control is utilized, and if the theoretically achievable peak load reduction is as projected (for example, if you utilize 100 load control participants who are each theoretically able to provide 1 kw of demand reduction, you would expect to get a 100 kw demand reduction), then add an additional amount of load control (for example, 10 additional participants) and check the projected theoretical reduction versus the linear programming result. (In our example, did 100 + 10 = 110 participants x 1 kw/participant yield 110 kw of reduction from the previous peak?)

Once the point has been reached at which additional increments of load control do not yield the projected theoretical results (for example, 110 participants yielded less than the projected 110 kw of reduction), then the physical limit of load control has been crossed. The analysis then backtracks to find the last point at which one additional projected increment of load control still yields one additional increment in the linear programming analysis. This point represents the physical limit for load control for a given year on the utility system, and that amount of load control is the maximum amount that is termed "usable" for the system for that year.

Q. What were the results of your analysis of load control for FPL's system?

A. Previous FPL analyses of the impact of load control programs on peak day load shape showed that the physical limit in regard to Summer peak was more restrictive than in regard to Winter peak. Consequently, FPL's 2004 analyses concentrated on the usable amount of load control "versus" FPL's projected Summer peak loads. The forecasted Summer peak day load shapes for 2009 and 2014 were used in the analyses.

The results of these analyses were that FPL could add up to another 150 MW of usable residential and/or small business load control (since the primary characteristics of these two programs are similar) in the 2005 through 2009 time frame, and another usable 60 MW in the 2010 through 2014 time frame, for a total usable incremental total of 210 MW over the 10-year period. Similar analyses showed that a much greater amount, approximately 600 MW over the 10-year period, of additional of large business load control (such as FPL's CDR program) would be usable on FPL's system. This greater amount of usable large business load control, compared to the amount of usable residential and/or small business load control, is due to the differences between the two types of programs in the payback of electrical demand when load control is released.

There is no immediate payback when control of large business customers' load is released, since these customers' typical electrical load is typically <u>not</u> driven by thermostatically-controlled equipment. In contrast, the electrical load of residential and/or small business customers typically drops off in the evening hours when load control is likely to be released and <u>is</u> typically driven by thermostatically-controlled equipment. Consequently, the payback of previously controlled load of residential and/or small business customers during these hours serves to increase their loads beyond what they would have been if load control had not been implemented.

The insight gained from these analyses of two types of load control programs with significant differences in payback characteristics is that, all else equal, a utility can use more of a load control program without payback than it can of a load control program with payback.

Q. What other insights into future load control at FPL were gained from the analyses?

A. In addition to the previously mentioned conclusion that, all else equal, "the smaller the payback, the greater amount of load control that is usable," one other insight was gained: all else equal, the longer the control duration that is allowed by tariff (or tolerable by participants), the greater amount of load control that is usable. These results have been seen in previous FPL analyses and were again confirmed in this recent work.

Q. How did FPL utilize the results of these analyses in its 2004 IRP work?

A. The usable amount of load control that was determined for each of these two types of load control programs was first compared to the achievable market potential projections that were independently developed for the two programs. Then the lower of these two values, the incremental MW that are usable on FPL's system or the achievable MW market potential that can be signed up, was used to develop an "achievable usable" level for the program (i.e., the "upper limit" for incremental signups). This lower value was then carried through the remainder of the analyses. (Mr. Brandt's testimony addresses how the achievable market potential projections for the DSM options were developed.)

In the case of residential and/or small business load control, the usable amount of incremental load control (210 MW) is significantly less than the achievable market potential for such programs (that was conservatively estimated to be over 500 MW for the 10-year period). Consequently, the lower value – the usable amount of 210 MW – for these programs was used as the achievable usable value for the remainder to the analyses.

Just the opposite was the case for large business load control. The achievable market potential value of 70 MW over the 10-year period was significantly lower than the 600 MW usable amount. Therefore, the lower market potential value of 70 MW was used as the achievable usable value for large business load control for the remainder of the analyses.

Q. When the results of the market potential analyses for the non-load control measures were combined with these results of the usable projections for the load control programs, how much achievable usable DSM in total was projected?

A. FPL projects that approximately 886 MW (Summer) at the generator of DSM for the 2005 through 2014 time period are achievable and usable. These DSM MW are potentially cost-effective since each individual DSM measure represented in this total has passed the cost-effectiveness screening. In the next step of determining what FPL's DSM Goals for 2005 through 2014 should be, these potentially cost-effective DSM measures were then combined into a DSM portfolio that was tested against the Supply Only resource plan.

Q. Before moving to this next step, please summarize the results of the work designed to determine the amount of achievable, usable, and potentially cost-effective DSM for the years 2005 through 2014.

A. This work can be summarized as follows:

1) FPL analyzed 224 DSM measures (that actually represented 329 measures as previously discussed), first without administrative costs or incentive payments, to determine which measures appeared to be potentially cost-effective versus CC capacity in the period beyond 2004. The 162 measures that survived this first screening were then evaluated to determine which ones had

payback periods for the participants of two years or less. 23 additional measures were eliminated by this analysis leaving 139 surviving measures. The measures were then reevaluated after administrative costs were added for each measure. 110 measures survived after this analysis and were carried forward for further evaluation. The Commission's approved cost-effectiveness methodology was utilized to perform these evaluations that were based on the RIM and Participant tests.

2) For each of these surviving 110 measures, FPL sought to determine an incentive level that would allow the measure to pass both the RIM and Participant tests. Such an incentive level could be determined for 54 of these 110 measures, while 56 measures were eliminated in this final screening step. Then, using the determined incentive level, an achievable market potential value for each measure was then developed. In determining the incentive levels for all measure, one measure was dropped from further consideration when it was determined that only a $1 incentive could be paid for the measure and have the measure pass both the RIM and Participant tests. Therefore, 53 DSM measures were carried forward for the remainder of the DSM Goals analyses work.

3) For the load control programs, an additional analysis was performed to determine how much load control was usable on

the FPL system. The results of these analyses were then compared with the achievable market potential results for load control to develop achievable usable values for the load control programs.

4) The end result of these efforts was a projection of approximately 886 MW (Summer) at the generator, of DSM that was achievable, usable, and potentially cost-effective for the 2005 through 2014 time period.

III. Development of the With DSM Resource Plan and Comparison of the Supply Only and With DSM Resource Plans

Q. How did FPL evaluate whether this amount of achievable, usable, and potentially cost-effective DSM was truly cost-effective?

A. The prior economic screening analyses determined which DSM measures were viewed as potentially cost-effective from the perspective of avoiding a single generating unit projected to come in-service in 2010. However, as previously discussed, the primary impact of adding DSM to the Supply Only resource plan will be to defer the in-service dates of a number of CC units. Therefore, to determine whether all or part of this DSM amount was truly cost-effective, it was necessary to analyze DSM from a resource plan perspective that accounts for the effects of multiple unit deferrals.

This approach allows two things to be determined. First, what would the implementation of this amount of DSM really accomplish in terms of displacing new generating units that otherwise would be built? Second, would this displacement of new units by DSM truly be cost-effective when comparing resource plans both with and without the incremental 886 MW of DSM?

The resource plan without DSM has already been determined; it is the Supply Only resource plan presented in Document No. SRS-4. To fairly compare the economics of this Supply Only resource plan and a second resource plan that utilizes this incremental 886 MW of DSM, it is necessary to examine the impacts on system average electric rates of the two plans. FPL performs this comparison by calculating a levelized system average electric rate based on each plan. This calculation for the Supply Only resource plan was performed in EGEAS when EGEAS was used to develop this resource plan. A depiction of this calculation is presented in Document No. SRS-9.

As shown in Document No. SRS-9, the levelized system average electric rate for the Supply Only resource plan is 8.7200 cents/kwh. If a resource plan which includes the incremental 886 MW of DSM can be constructed which results in a lower levelized system average electric rate, then the inclusion of the incremental DSM is cost-effective.

Q. How did FPL construct a resource plan with DSM?

A. We began with the Supply Only resource plan shown in Document No. SRS-4 and the 10-year incremental DSM achievable potential level of 886 MW. The objective was to construct a resource plan that included the incremental 886 MW of DSM and that had comparable reserve margins and LOLP values to that of the Supply Only resource plan.

FPL developed this With DSM resource plan using an approach that had four basic steps. The first step in this approach was to determine how much of the 886 MW of DSM could be implemented for each year of the 2005 through 2014 time period. Much of this work had been carried out in developing the overall achievable market potential values for conservation. These estimates were then combined with data from the analyses of the usable amounts of load control to develop overall annual estimates of achievable usable DSM.

The second step determined how many MW of DSM would be needed to avoid or defer the supply additions shown in the Supply Only resource plan. In making this determination, FPL started with Document No. SRS-3 that presented FPL's annual and cumulative resource needs for 2005 through 2010 assuming that these resource needs would be met by <u>supply options only.</u>

However, if these resources were to be supplied by DSM, the resource needs would be smaller due to the 20% reserve margin criterion that FPL uses. In other words, if FPL has load growth of 100 MW, then 120 MW of either new generation and/or purchased power must be added to maintain the 20% reserve margin. Yet if FPL could meet this load growth by DSM, then only 100 MW of new DSM would be needed to maintain the 20% reserve margin.

Therefore, the resource needs for 2005 through 2014 are <u>smaller by 20%</u> if the needs can be met by DSM. Document No. SRS-10 presents FPL's resource needs for this time period <u>if</u> the needs could be met solely by DSM. Column (9) on this document is identical to Column (9) on Document No. SRS-3. Both of these Column (9)'s show what FPL's resource needs are if those needs are met solely by supply options. By comparison, Column (10) on Document No. SRS-10 shows what the reduced resource needs are if met solely by DSM.

The third step of this approach was to use the DSM resource need values from Column (10) of Document No. SRS-10, plus the achievable usable levels for DSM, to set annual MW targets for DSM.

Then, using linear programming techniques that solve the question of how to meet these annual DSM MW targets with the achievable usable amount of DSM in the most cost-effective way possible, a DSM portfolio is selected. This selection process determines which DSM measures are chosen and how much of each selected measure is chosen per year.

This DSM "portfolio" then forms the basis for constructing the With DSM resource plan. In the With DSM resource plan, the selected DSM measures - in the appropriate amount per year - are combined with needed supply options to ensure that FPL's resource needs are met for all years in the 2005 through 2014 time period. That work was carried out again using FPL's EGEAS model. Document No. SRS-11 presents the resulting With DSM resource plan and the annual Summer reserve margin values for this plan. By comparing the reserve margin values for the Supply Only resource plan (shown in Document No. SRS-4) and for this With DSM resource plan, it is evident that the two plans are comparable in regard to this reliability criterion. A comparison of annual LOLP projections for each resource plan also showed the two resource plans were comparable from that reliability perspective as well.

Q. How much incremental DSM is included in this With DSM resource plan for the 2005 through 2014 time period?

A. All of the incremental total of 886 MW (Summer) at the generator of DSM that was previously discussed are included in this plan.

Q. How did this resource plan compare economically with the Supply Only resource plan?

A. A levelized system average electric rate for the With DSM resource plan was calculated in EGEAS in the development of the resource plan so that it could be compared to the equivalent electric rate for the Supply Only resource plan. Document No. SRS-12 presents a depiction of the levelized system average electric rate calculation for the With DSM resource plan. The resulting levelized system average electric rate value for the With DSM resource plan is 8.7156 cents/kwh. This electric rate is <u>lower</u> than the 8.7200 rate for the Supply Only resource plan. Consequently, the DSM portfolio included in the With DSM resource plan is both truly cost-effective and represents the maximum amount of achievable, usable, and cost-effective DSM available to FPL for the 2005 through 2014 time period.

Q. What else do you conclude from a comparison of the two resource plans?

A. The amount of DSM included in the With DSM resource plan should be set as FPL's new DSM Goals for the 2005 through 2014 time period. This amount is 886 MW (Summer) at the generator or an equivalent amount of 802 MW (Summer) at the meter.

Although DSM values at the generator are typically used in resource planning work, DSM values at the meter are typically used when referring to DSM program implementation. Therefore, FPL will use the "at the meter" designation in referring to its proposed Summer MW DSM Goals amount of 802 MW. (The corresponding Winter MW and Energy total Goals values, plus the annual Goals values for Summer MW, Winter MW, and Energy, are presented and discussed in Mr. Brandt's testimony.)

IV. Summary of Analyses

Q. How would you summarize the 2004 IRP analyses which were performed in order to develop the proposed DSM goals?

A. I would summarize the entire process and the results in general as follows:

1) FPL utilized its basic IRP process to determine how much DSM was cost-effective to add in the 2005 through 2014 time frame. This is the correct approach to take to make such a determination. Economic impacts were determined on a levelized system average electric rate basis that is the correct and equitable way to compare supply and DSM options that have different effects on a utility system.

2) FPL included the appropriate key assumptions in its analyses regarding supply options (i.e., Martin Unit No. 8, Manatee Unit No. 3, and Turkey Point Unit No. 5) to which FPL has either already committed or, due to the size (1,144 MW) and nearness of its planned in-service date (2007), incremental new DSM cannot reasonably avoid or defer.

3) The initial economic screening of DSM options was performed using an appropriate tool, the Commission's approved cost-effectiveness methodology, and an appropriate type of supply option (i.e., new CC capacity). This screening allowed FPL to determine optimal incentive payments and achievable market potential levels for each DSM measure that was shown to be potentially cost-effective in the cost-effectiveness screening. Additional analyses of load control programs further refined the achievable usable levels for these DSM options.

4) Both the Supply Only and With DSM resource plans were developed using the EGEAS model and were designed to provide adequate system reliability. The two plans are comparable in regard to system reliability criteria over the 10-year period in question.

5) Since the With DSM resource plan results in a lower system average levelized rate, it is a more cost-effective resource plan. Consequently, FPL proposes this amount of DSM, 802 MW (Summer) at the meter (that corresponds to 886 Summer MW at the generator) as its new DSM Goals for the 2005 through 2014 time frame.

Q. Does this conclude your testimony?

A. Yes.

Overview of FPL's IRP Process
(An Excerpt from FPL's 2004 Site Plan)

Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL developed an integrated resource planning (IRP) process in the early 1990's and has since utilized the process to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be considered. The projected timing and type of potential new power plants, the primary subject of this document, is determined as part of the IRP process work. This section discusses how FPL applied this process in its 2003 and early 2004 planning work.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental "steps" to FPL's resource planning. These steps can be described as follows:

Step 1: Determine the magnitude and timing of FPL's projected new resource needs;

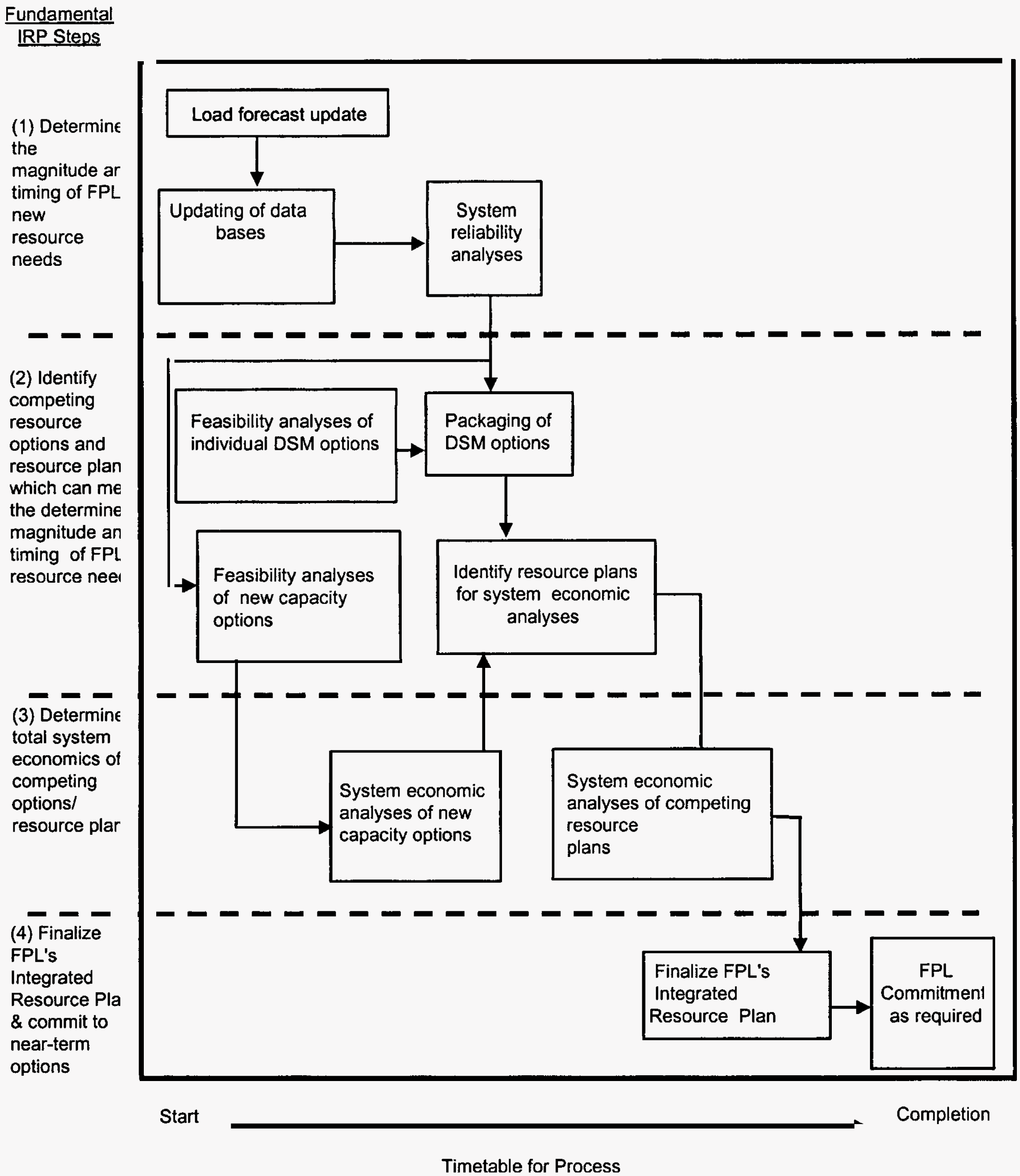
Step 2: Identify which resource options can meet the determined magnitude and timing of the specific resource needs;

Step 3: Determine the economics for the total utility system with each of the competing options and resource plans; and,

Step 4: Select a resource plan and make commitments, as required.

Figure III.A.1 graphically outlines the 4 steps.

Overview of FPL's IRP Process



(Normal time period: approx. 6-7 months)

Figure III.A.1

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of these four resource planning steps – determining the magnitude and timing of FPL's projected resource needs – is essentially a determination of how many megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions are expected to be needed. Also determined in this step is when the capacity is expected to be needed to meet FPL's planning criteria. This step is often referred to as a reliability assessment for the utility system.

Step 1 generally starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information which is used in many of the fundamental steps in resource planning. Examples of this new information include: delivered fuel price projections, current financial and economic assumptions, as well as power plant capability and reliability assumptions. During its recent IRP work, FPL made four key assumptions. These assumptions include near-term construction capacity additions through the summer of 2007, short-term firm capacity purchase additions through late spring of 2007, long-term DSM implementation through 2009, and the projected replacement of the Southern Company Unit Power Sales (UPS) contracts that end in May, 2010.

The first of these assumptions incorporates FPL's announced plans to add near-term capacity through various construction projects. These construction projects include the addition of a new combined cycle (CC) unit at Manatee, the conversion of two existing CT's at Martin into a new CC unit and a new CC unit at Turkey Point. The Manatee and Martin additions are under construction with a scheduled in-service date of June, 2005. These capacity additions were approved by the FPSC in November 2002 after comparing them to proposals that were received in response to Requests for Proposals (RFP's) that solicited alternatives for meeting FPL's 2005/2006 capacity needs. These capacity additions also received certification under the Florida Electrical Power Plant Siting Act (PPSA) in April, 2003. The new CC unit at FPL's Turkey Point site is scheduled for mid-2007. FPL selected this construction option after evaluating competing proposals provided in response to FPL's 2003 RFP. FPL recently (March 8, 2004) filed for a request for approval of a Determination of Need for this unit with the FPSC and also has pending an application for PPSA certification of this unit with a decision expected in the 1st Quarter of 2005.

The second of these assumptions involves short-term firm capacity purchase additions. These firm capacity purchases are provided by a combination of utility and independent power producers. The total capacity and duration of these purchases have changed somewhat from what was presented in the 2003 Site Plan and the annual total capacity values for these purchases are presented in Table I.D.1 as "Other Firm Capacity Purchases" up to mid-2007. These purchase amounts are included in FPL's resource planning work.

The third of these assumptions involves DSM. Since 1994, FPL's resource planning work has incorporated the DSM MW called for in FPL's approved DSM goals in its analyses. This was again the case in FPL's most recent planning work, as its approved DSM goals at the time this Site Plan was filed were included.

The fourth of these assumptions anticipates a replacement of the UPS purchases that are currently scheduled to end in May, 2010 with other purchases. These purchases are presented in Table I.D.1 as "Other Firm Capacity Purchases" for the years beyond mid-2010.

These assumptions and much of the other updated information are used is the first fundamental step: the determination of the magnitude and the timing of FPL's projected resource needs. This determination is accomplished by system reliability analyses which are typically based on the dual planning criteria of a minimum peak period reserve margin of 20% (FPL applies this to both summer and winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry.

Historically, both deterministic and probabilistic methodologies have been employed in system reliability analysis. The calculation of excess firm capacity at the time of annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. The reserve margin calculation provides an indication of how much extra generation a system has above the forecasted peak load. A value of 20% is used as the reserve margin planning criteria to establish FPL's need. However, deterministic methods do not take into account probabilistic-related elements such as unit reliability and the value of being part of an interconnected system. Therefore, probabilistic methodologies have been used to provide additional information on the reliability of a generating system.

There are a number of probabilistic methods that are being used to perform system reliability analyses. Of these, the most widely used is loss-of-load probability or LOLP. 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 reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in units of the "number of times per year" that the system demand could not be served. The standard for LOLP accepted throughout the industry is a maximum of 0.1 day per year and FPL uses this LOLP standard. LOLP analyses require complex statistical calculations and are carried out using the Tie Line Assistance and Generation Reliability (TIGER) model.

The end result of the first fundamental step of resource planning is a forecast of the amount and timing of capacity resources needed to meet both the reserve margin and LOLP criteria for system reliability. This information is used in the second fundamental step: identifying resource options and resource plans that can meet the projected magnitude and timing of FPL's resource needs.

Step 2: Identify Resource Options and Plans which can meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, feasibility analyses of new capacity options are carried out to determine which new capacity options appear to be the most economic. These analyses also consider capacity size (MW), estimated development and construction schedules, and operating parameters and costs.

The individual new capacity options are then "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's new projected resource needs are met and the planning criteria are satisfied. The creation of these competing resource plans is typically carried out using dynamic programming techniques with the objective of forming alternative resource plans within the constraints applied to the resource planning process. The constraints include recognition of reserve margin criteria, feasible resource option performance characteristics, and construction or DSM implementation lead time. The development of these resource plans has been conducted using the EGEAS (Electric Generation Expansion Analysis System) computer model. When DSM options are being addressed, other computer models using both linear and non-linear programming techniques are used. For planning purposes, only FPL construction options were included in FPL's most recent planning analyses addressing FPL's 2008-2013 forecasted capacity needs.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs were identified.

Step 3: Determining the Total System Economics:

At the completion of fundamental steps 1 & 2, viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for comparing the system economics of these resource plans. The EGEAS model is employed to conduct the basic economic analyses of the resource plans.

The basic economic analysis of the competing resource plans focuses on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the intent of minimizing FPL's levelized system average rate (i.e., a Rate Impact Measure or RIM methodology). However, in cases such as those existing for FPL's most recent planning work (wherein the DSM contribution was incorporated and the only competing options were new generating units) comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements are equivalent. This basic economic analysis captures the capital and operating costs of new resource options as well as the impact these new resource options have on FPL's system fuel costs.

In addition, other system costs of these resource plans must be incorporated as needed into the economic analyses. These include transmission-related costs, such as integration and system losses; increased operating costs of existing generating units, and impacts on FPL's capital structure. These costs are evaluated separately and in addition to the system operating cost values developed in the EGEAS analysis to complete the system cost impact of each resource plan. FPL considered the results of all of the economic analyses carried out in Step 3, before a determination of FPL's resource plan was made.

Step 4: Finalizing FPL's Current Resource Plan

The results of the work performed in the previous three fundamental steps are evaluated by FPL management and a decision is made establishing FPL's resource plan. The current resource plan is presented in the following section.

FPL's Resource Plan in its 2004 Ten-Year Power Plant Site Plan
(with Current DSM Goals)

Year	Incremental DSM (MW) (1)	Incremental Generation Capacity (MW) (2)	Incremental New Purchases (MW) (3)
2005	79	1,896	---
2006	78	---	---
2007	77	1,144	---
2008	78	324	---
2009	75	1,144	---
2010	25	---	931
2011	0	1,144	---
2012	0	---	---
2013	0	1,144	---

(1) DSM MW represent FPL's approved DSM Goals set in 1999 for the years 2005 through 2009 with MW values "at the generator". No DSM Goals were set for the 2010 - on time period. Values shown for 2005 through 2009 represent 12-month incremental values (September-to-August) and the 2010 value shown represents a 4-month incremental value (September-through-December) that captures the effects of DSM participants signed up in 2009 after August of that year.

(2) Generation MW additions, by year, are as follows:
2005: Manatee Unit No. 3 (1,107 MW) and Martin Unit No. 8 conversion (789 MW)
2006: none
2007: Turkey Point Unit No. 5 (1,144 MW)
2008: Midway CT Unit Nos. 1A and 1B (total MW = 324 MW)
2009: Corbett CC Unit No. 1 (1,144 MW)
2010: none
2011: Unsited CC Unit (1,144 MW)
2012: none
2013: Unsited CC Unit (1,144 MW)

(3) Values shown represent new purchases projected for the time period shown. The 2010 purchase of 931 MW is projected to replace FPL's current UPS contract with Southern Company that ends in May, 2010.

Projected FPL Resource Needs Without Incremental DSM

August of the Year	(1) Projections of FPL Unit Capability (MW) (1)	(2) Projections of Firm Purchases (MW) (2)	(3) = (1) + (2) Projection of Total Capacity (MW)	(4) Peak Load Forecast (MW)	(5) Summer DSM Forecast w/ no Signups after 2004 (MW)	(6) = (4) - (5) Forecast of Firm Peak (MW)	(7) = (3) - (6) Forecast of Summer Reserves (MW)	(8) = (7) / (6) Forecast of Summer Res.Margins (%)	(9) = ((6) * 1.20)-(3) Supply Only MW Needed to Meet Reserve Margin (MW)
--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2005	21,021	3,127	24,148	20,799	1,537	19,262	4,886	25.4%	**(1,034)**
2006	21,020	2,991	24,011	21,331	1,537	19,794	4,217	21.3%	**(258)**
2007	22,162	2,046	24,208	21,851	1,537	20,314	3.894	19.2%	**169**
2008	22,162	2,046	24,208	22,289	1,537	20,752	3.456	16.7%	**694**
2009	22,162	1,995	24,157	22,784	1,537	21,247	2.910	13.7%	**1,339**
2010	22,162	1,952	24,114	23,294	1,537	21,757	2,357	10.8%	**1,994**
2011	22,162	1,907	24,069	23,783	1,537	22,246	1,823	8.2%	**2,626**
2012	22,162	1,907	24,069	24,279	1,537	22,742	1,327	5.8%	**3,221**
2013	22,162	1,907	24,069	24,784	1,537	23,247	822	3.5%	**3,827**
2014	22,162	1,907	24,069	25,300	1,537	23,763	306	1.3%	**4,447**

(1) Projections include the contributions of Manatee Unit No. 3 and Martin Unit No. 8 Conversion in 2005, and Turkey Point Unit No. 5 in 2007

(2) Projections include approximately 470 MW of "put options" for June 2005 through May 2007 exercised in 2003 and 931 MW of new purchases in 2010 - on to replace the current UPS contract that ends in May 2010.

The Supply Only Resource Plan for 2005 - 2014
(Shown in Columns (3) - (5) Below)

	(1)	(2)	(3)	(4)	(5)	(6) = (1)+(2) +(3)+(4)+(5)	(7)	(8)	(9)	(10) = (7) - (8) - (9)	(11) = (6) - (10)	(12) = (11) / (10)
			Supply Additions						DSM Additions			
August of the Year	Projections of FPL Unit Capability (MW) (1)	Projections of Firm Purchases (MW) (2)	Cumulative New Purchases (MW)	Cumulative New CC Additions (MW) (3)	Cumulative New CT Additions (MW) (3)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Summer DSM Forecast w/ no Signups after 2004 (MW) (4)	Cumulative Summer DSM Additions after 2004 (MW) (4)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Res.Margins (%)
2005	21,021	3,127	0	0	0	24,148	20,799	1,537	0	19,262	4,886	25.4%
2006	21,020	2,991	0	0	0	24,011	21,331	1,537	0	19,794	4,217	21.3%
2007	22,162	2,046	170	0	0	24,378	21,851	1,537	0	20,314	4,064	20.0%
2008	22,162	2,046	0	0	648	24,856	22,289	1,537	0	20,752	4,104	19.8%
2009	22,162	1,995	0	1,144	648	25,949	22,784	1,537	0	21,247	4,702	22.1%
2010	22,162	1,952	0	2,288	648	27,050	23,294	1,537	0	21,757	5,293	24.3%
2011	22,162	1,907	0	2,288	648	27,005	23,783	1,537	0	22,246	4,759	21.4%
2012	22,162	1,907	0	3,432	648	28,149	24,279	1,537	0	22,742	5,407	23.8%
2013	22,162	1,907	0	3,432	648	28,149	24,784	1,537	0	23,247	4,902	21.1%
2014	22,162	1,907	0	4,576	648	29,293	25,300	1,537	0	23.763	5,530	23.3%

(1) Projections include the contributions of Manatee Unit No. 3 and Martin Unit No. 8 Conversion in 2005 and Turkey Point Unit No. 5 in 2007.

(2) Projections include approximately 470 MW of "put options" for June 2005 through May 2007 exercised in 2003 and 931 MW of new purchases in 2010 - on to replace the current UPS contract that ends in May 2010.

(3) A CC unit addition is assumed to add 1,144 MW (Summer) and a CT unit addition is assumed to add 162 MW (Summer).

(4) DSM MW shown are "at the generator" values for August of each year shown.

Summary of Results of the Cost-Effectiveness Screening

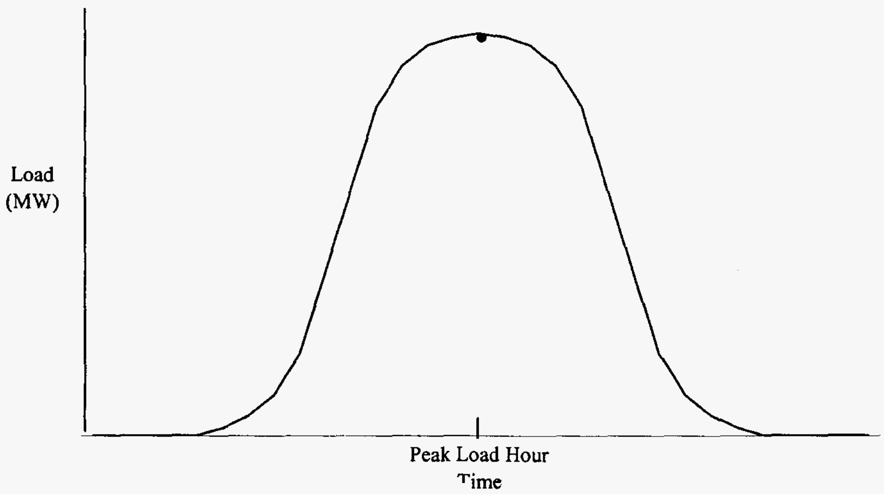
224 = Number of DSM measures submitted by PMO for cost-effectiveness screening after removing numerous "identical" measures in its comprehensive list of 329 DSM measures. In this list, an "identical" measure is the same measure, but counted once in reference to existing construction and counted a second time for either new construction or as a Code Utility Evaluation (CUE) measure. Only one of each "identical" measure was included in the screening analyses.

Cost-Effectiveness Screening Step No.	Description of Screening Step	Number of Measures at Start of Screening Step	RIM Test Only		Both RIM & Participant Tests		Payback > 2 Years		Number of Measures Passing Screening Step
			Pass	Fail	Pass	Fail	Pass	Fail	
1	With Revenue Losses only (No Administrative costs or Incentive Payments)	224	162	62	---	---	---	---	162
2	Payback to Participant Greater than 2 Years	162	---	---	---	---	139	23	139
3	With Administrative costs & Revenue Losses only (No Incentive Payments)	139	110	29		---		---	110
4	With Incentive Payments, Administrative costs, & Revenue Losses	110	---		54	56	---	---	54

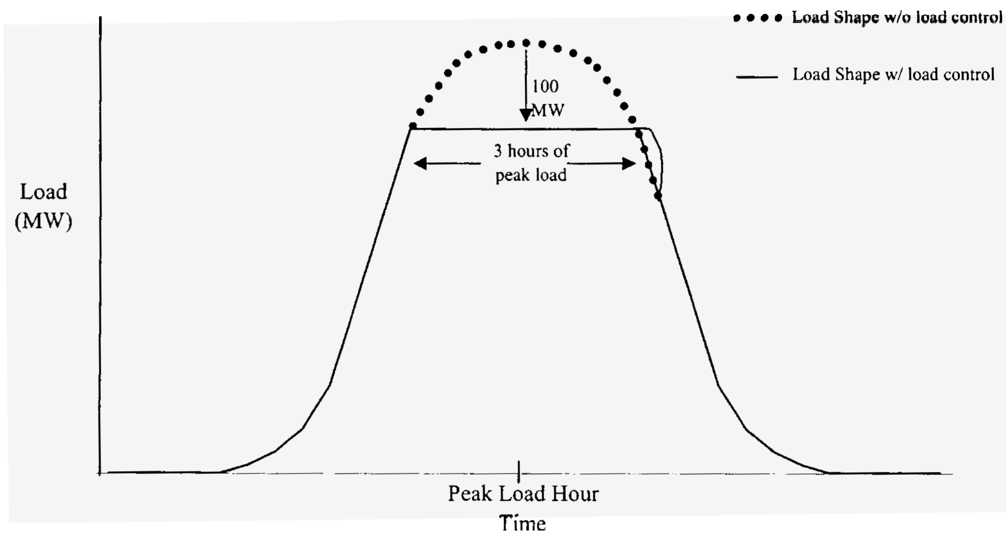
Conclusion: **54** DSM measures of the 224 measures submitted by PMO for evaluation survived all of the cost-effectiveness screening steps.

92 Total DSM measures survived the cost-effectiveness screening steps after accounting for the "identical" measures that correspond to some of these 54 surviving measures.

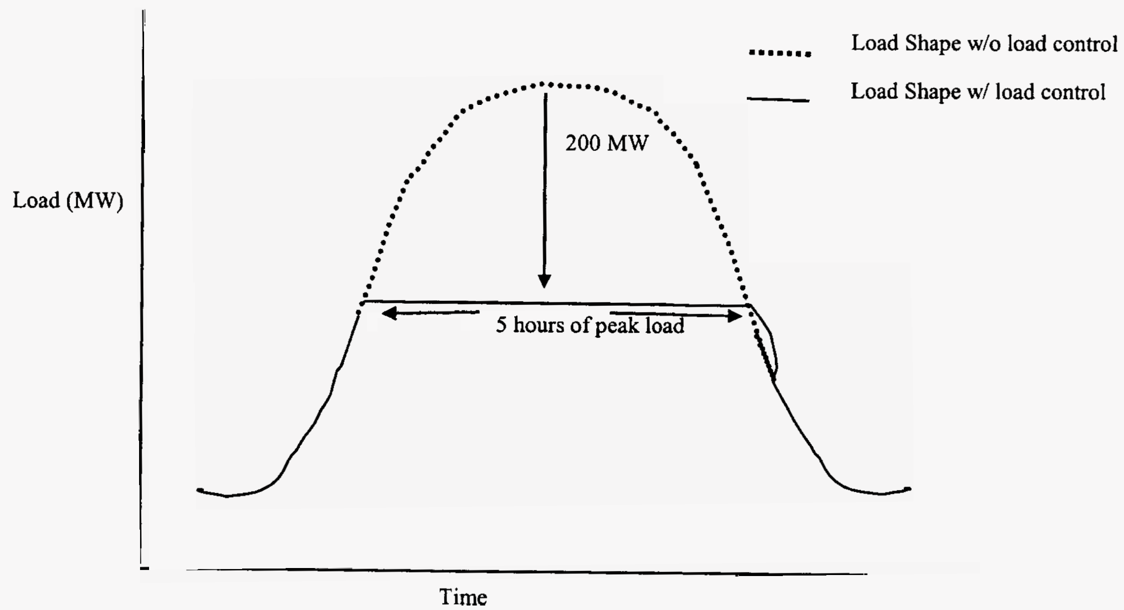
Hypothetical Utility Peak Day Load Shape



Representative Effect of Implementing 100 MW of Load Control on the Hypothetical Utility Peak Day Load Shape



Representative Effect of Implementing 200 MW of Load Control on the Hypothetical Utility Peak Day Load Shape



Calculation of System Average Levelized Rate for the Supply Only Resource Plan

Year	(1) Annual Discount Factor 7.93%	(2) Annual Revenue Requirements [$ 000]	(3) Annual Energy Sales (@ Meter) [GWh]	(4) = (2) / (3) Nominal Annual Rate [cents/kWh]	(5) = (4) * (1) NPV Annual Rate [cents/kWh]	(6) Nominal Levelized System Average Rate [cents/kWh]	(7) = (6) * (1) NPV Levelized System Average Rate [cents/kWh]
2004	1.000	7,852,664	101,086	7.76830	7.76830	8.71998	8.71998
2005	0.927	7,836,725	103,939	7.53973	6.98576	8.71998	8.07929
2006	0.858	7,971,975	107,066	7.44585	6.39190	8.71998	7.48568
2007	0.795	8,115,604	109,369	7.42039	5.90201	8.71998	6.93568
2008	0.737	8,355,785	111,654	7.48364	5.51498	8.71998	6.42609
2009	0.683	8,753,228	113,706	7.69812	5.25623	8.71998	5.95394
2010	0.633	9,432,938	116,201	8.11778	5.13552	8.71998	5.51648
2011	0.586	9,734,224	118,530	8.21246	4.81369	8.71998	5.11117
2012	0.543	10,168,751	120,749	8.42140	4.57348	8.71998	4.73563
2013	0.503	10,464,969	123,110	8.50050	4.27725	8.71998	4.38769
2014	0.466	10,926,077	125,543	8.70306	4.05742	8.71998	4.06531
2015	0.432	11,326,681	127,917	8.85471	3.82482	8.71998	3.76662
2016	0.400	11,805,696	130,401	9.05338	3.62330	8.71998	3.48987
2017	0.371	12,166,703	132,856	9.15781	3.39581	8.71998	3.23346
2018	0.344	12,688,560	135,200	9.38503	3.22437	8.71998	2.99588
2019	0.318	13,280,904	137,641	9.64894	3.07148	8.71998	2.77576
2020	0.295	13,674,377	140,164	9.75598	2.87737	8.71998	2.57182
2021	0.273	14,327,527	142,550	10.05088	2.74655	8.71998	2.38286
2022	0.253	14,994,811	145,021	10.33975	2.61789	8.71998	2.20778
2023	0.235	15,687,098	147,644	10.62495	2.49244	8.71998	2.04557
2024	0.217	16,175,856	150,438	10.75251	2.33704	8.71998	1.89527
2025	0.201	16,995,390	153,243	11.09048	2.23339	8.71998	1.75602
2026	0.187	17,294,909	153,243	11.28594	2.10576	8.71998	1.62700
2027	0.173	17,691,359	153,243	11.54464	1.99577	8.71998	1.50746
2028	0.160	18,055,487	153,243	11.78226	1.88719	8.71998	1.39670
2029	0.148	18,487,185	153,243	12.06397	1.79034	8.71998	1.29408
2030	0.138	18,863,981	153,243	12.30985	1.69261	8.71998	1.19900
2031	0.127	19,337,816	153,243	12.61905	1.60764	8.71998	1.11090
2032	0.118	19,499,147	153.243	12.72433	1.50194	8.71998	1.02928
					105.70226		105.70226

Levelized System Average Rate (2004 - 2032, 2004 cents/kWh) = **8.720**

Projected FPL Resource Needs If Needs are Met Solely by DSM

	(1)	(2)	(3) = (1) + (2)	(4)	(5)	(6) = (4) - (5)	(7) = (3) - (6)	(8) = (7) / (6)	(9) = ((6) * 1.20)-(3)	(10) = (9) / 1.20
August of the Year	Projections of FPL Unit Capability (MW) (1)	Projections of Firm Purchases (MW) (2)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Summer DSM Forecast w/ no Signups after 2004 (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Res.Margins (%)	Supply Only MW Needed to Meet Reserve Margin (MW)	DSM Only MW Needed to Meet Reserve Margin (MW)
2005	21,021	3,127	24,148	20,799	1,537	19,262	4,886	25.4%	**(1,034)**	**(861)**
2006	21,020	2,991	24,011	21,331	1,537	19,794	4,217	21.3%	**(258)**	**(215)**
2007	22.162	2.046	24.208	21,851	1,537	20,314	3,894	19.2%	**169**	**141**
2008	22,162	2,046	24.208	22,289	1,537	20,752	3,456	16.7%	**694**	**579**
2009	22.162	1,995	24.157	22,784	1,537	21,247	2,910	13.7%	**1,339**	**1,116**
2010	22.162	1,952	24,114	23,294	1,537	21,757	2,357	10.8%	**1,994**	**1,662**
2011	22,162	1,907	24,069	23,783	1,537	22,246	1,823	8.2%	**2,626**	**2,189**
2012	22.162	1,907	24,069	24,279	1,537	22,742	1,327	5.8%	**3,221**	**2,685**
2013	22.162	1,907	24,069	24,784	1,537	23,247	822	3.5%	**3,827**	**3,190**
2014	22,162	1,907	24,069	25,300	1,537	23,763	306	1.3%	**4,447**	**3,706**

(1) Projections include the contributions of Manatee Unit No. 3 and Martin Unit No. 8 Conversion in 2005, Turkey Point Unit No. 5 in 2007

(2) Projections include approximately 470 MW of "put options" for June 2005 through May 2007 exercised in 2003 and 931 MW of new purchases in 2010 - on to replace the current UPS contract that ends in May 2010.

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Document No. SRS-10
Page 1 of 1

FPL's With DSM Resource Plan for 2005 - 2014
(Shown in Columns (3) - (5) and (9) Below)

	(1)	(2)	(3)	(4)	(5)	(6) = (1)+(2) +(3)+(4)+(5)	(7)	(8)	(9)	(10) = (7) - (8) - (9)	(11) = (6) - (10)	(12) = (11) / (10)
			Supply Additions						DSM Additions			
August of the Year	Projections of FPL Unit Capability (MW) (1)	Projections of Firm Purchases (MW) (2)	Cumulative New Purchases (MW)	Cumulative New CC Additions (MW) (3)	Cumulative New CT Additions (MW) (3)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Summer DSM Forecast w/ no Signups after 2004 (MW) (4)	Cumulative Summer DSM Additions after 2004 (MW) (4)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Res.Margins (%)
2005	21,021	3,127	0	0	0	24,148	20,799	1,537	55	19,207	4,941	25.7%
2006	21,020	2,991	0	0	0	24,011	21,331	1,537	132	19,662	4,349	22.1%
2007	22,162	2,046	0	0	0	24,208	21,851	1,537	208	20,106	4,102	20.4%
2008	22,162	2,046	0	0	324	24,532	22,289	1,537	290	20,462	4,070	19.9%
2009	22,162	1,995	0	1,144	324	25,625	22,784	1,537	376	20,871	4,754	22.8%
2010	22,162	1,952	0	1,144	324	25,582	23,294	1,537	465	21,292	4,290	20.1%
2011	22,162	1,907	0	2,288	324	26,681	23,783	1,537	557	21,689	4,992	23.0%
2012	22,162	1,907	0	2,288	324	26,681	24,279	1,537	652	22,090	4,591	20.8%
2013	22,162	1,907	0	3,432	324	27,825	24,784	1,537	750	22,497	5,328	23.7%
2014	22,162	1,907	0	3,432	324	27,825	25,300	1,537	852	22,911	4,914	21.4%

(1) Projections include the contributions of Manatee Unit No. 3 and Martin Unit No. 8 Conversion in 2005 and Turkey Point Unit No. 5 in 2007.

(2) Projections include approximately 470 MW of "put options" for June 2005 through May 2007 exercised in 2003 and 931 MW of new purchases in 2010 - on to replace the current UPS contract that ends in May 2010.

(3) A CC unit addition is assumed to add 1,144 MW (Summer) and a CT unit addition is assumed to add 162 MW (Summer).

(4) DSM MW shown are "at the generator" values for August of each year shown.

(5) The 852 MW of incremental DSM at the generator shown above for 2014 represents DSM signups through August 2014 only. When DSM signups for the remaining 4 months, September through December, of 2014 are included, the incremental DSM signups through the end of 2014 result in an incremental DSM total of 886 MW at the generator.

Exhibit No. ______
Document No. SRS-12

Calculation of System Average Levelized Rate for the With DSM Resource Plan

Year	[1] Annual Discount Factor 7.93%	[2] Annual Revenue Requirements [$ 000]	[3] Annual Energy Sales (@ Meter) [GWh]	[4] = [2] / [3] Nominal Annual Rate [cents/kWh]	[5] = [1] * [4] NPV Annual Rate [cents/kWh]	[6] Nominal Levelized System Average Rate [cents/kWh]	[7] = [1] * [6] NPV Levelized System Average Rate [cents/kWh]
2004	1.000	7,852,664	101,086	7.76830	7.76830	8.7156	8.71559
2005	0.927	7,861,720	103,879	7.56815	7.01209	8.7156	8.07523
2006	0.858	7,987,383	106,896	7.47211	6.41444	8.7156	7.48191
2007	0.795	8,118,150	109,107	7.44054	5.91804	8.7156	6.93219
2008	0.737	8,330,343	111,301	7.48452	5.51563	8.7156	6.42286
2009	0.683	8,725,002	113,254	7.70392	5.26019	8.7156	5.95095
2010	0.633	9,262,572	115,648	8.00928	5.06688	8.7156	5.51371
2011	0.586	9,707,440	117,870	8.23572	4.82732	8.7156	5.10860
2012	0.543	9,991,685	119,979	8.32786	4.52268	8.7156	4.73325
2013	0.503	10,438,298	122,226	8.54016	4.29721	8.7156	4.38548
2014	0.466	10,737,959	124,544	8.62182	4.01955	8.7156	4.06327
2015	0.432	11,261,487	126,858	8.87724	3.83455	8.7156	3.76472
2016	0.400	11,582,519	129,342	8.95496	3.58391	8.7156	3.48812
2017	0.371	12,107,973	131,797	9.18684	3.40657	8.7156	3.23183
2018	0.344	12,460,636	134,142	9.28914	3.19143	8.7156	2.99438
2019	0.318	13,050,292	136,583	9.55484	3.04152	8.7156	2.77437
2020	0.295	13,656,004	139,105	9.81705	2.89538	8.7156	2.57053
2021	0.273	14,110,055	141,492	9.97233	2.72508	8.7156	2.38166
2022	0.253	14,783,416	143,962	10.26897	2.59997	8.7156	2.20667
2023	0.235	15,477,744	146,585	10.55889	2.47695	8.7156	2.04454
2024	0.217	16,191,261	149,379	10.83905	2.35585	8.7156	1.89432
2025	0.201	17,013,395	152,184	11.17949	2.25132	8.7156	1.75514
2026	0.187	17,309,553	152,184	11.37410	2.12221	8.7156	1.62618
2027	0.173	17,701,878	152,184	11.63189	2.01085	8.7156	1.50670
2028	0.160	18,062,660	152,184	11.86896	1.90108	8.7156	1.39600
2029	0.148	18,490,278	152,184	12.14995	1.80310	8.7156	1.29343
2030	0.138	18,834,975	152,184	12.37645	1.70176	8.7156	1.19840
2031	0.127	19,302,535	152,184	12.68368	1.61587	8.7156	1.11035
2032	0.118	19,460,325	152,184	12.78737	1.50939	8.7156	1.02876
					105.64912		105.64912

Levelized System Average Rate (2004 - 2032, 2004 cents/kWh) = 8.7156