FPL

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 971004-EG

ADOPTION OF NUMERIC CONSERVATION GOALS

FEBRUARY 1, 1999

TESTIMONY & EXHIBITS OF:

S. R. SIM

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF STEVEN R. SIM

DOCKET NO. 971004-EG

FEBRUARY 1, 1999

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 Department.

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 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 Bachelors degree in Mathematics in 1973. I subsequently earned a Masters 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 at Cape Canaveral 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., which were 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 assumed the position of Supervisor of Supply and Demand Analysis in the System Planning Department, where my responsibilities included the cost-effectiveness analyses of a variety of individual supply and DSM options. In 1993 I assumed my current responsibilities in the Resource Assessment & Planning Department (formerly the System Planning Department).

Q. What is the purpose of your testimony'?

A. The purpose of my testimony is to explain the integrated resource planning (IRP) work which FPL performed during 1998 which led to the determination of the level of cost-effective DSM which FPL is now proposing as its DSM goals. (FPL's 1998 IRP work actually concluded in January, 1999. In my testimony, all of this work will be referred to as the 1998 IRP work.)

Q. How is your testimony structured?

A. My testimony is presented in 4 parts. First, I briefly introduce FPL's IRP approach to evaluating resource options such as DSM and then discuss the key planning assumptions which were used in FPL's 1998 IRP work. Second, I discuss the first half of the analyses which were performed in determining the achievable potential level of cost-effective DSM. The cost-effectiveness screening of individual DSM options is addressed in this section. (Mr. Brandt's testimony addresses the second half of this work.) Third, the development and comparison of competing resource plans, with and without additional DSM, is addressed. Finally, I summarize these analyses, compare the resulting proposed levels of DSM with FPL's current DSM goals, and discuss why different levels of DSM are now being proposed.

Q. Are you sponsoring any exhibits?

A. Yes, the exhibits consist of the following 13 documents:

Document No. 1:	Overview of FPL's IRP Process
Document No. 2:	Peak Load & Net Energy for Load (NEL) Projection: 2001-2009
Document No. 3:	1998 Fuel Cost Forecast
Document No. 4:	Projected FPL Resource Needs (MW): 2001-2009
Document No. 5:	Hypothetical Utility Peak Day Load Shape
Document No. 6:	Representative Effect of Implementing 100 MW of Load Control on the Hypothetical Utility Peak Day Load Shape
Document No. 7:	Representataive Effect of Implementing 200 MW of Load Control on the Hypothetical Utility Peak Day Load Shape

Document No. 8:	Supply Only Resource Plan
Document No. 9:	Calculation of System Average Levelized Rate for the Supply Only Resource Plan
Document No. 10:	Competing Resource Plans
Document No. 11:	Comparison of Annual Reserve Margins and LOLP Values for the Supply Only and With DSM Resource Plans
Document No. 12:	Calculation of System Average Levelized Rate for the With DSM Resource Plan
Document No. 13:	Comparison of 1994 & 1998 Projections for a CC Unit: Selected Cost & Performance Values

I. FPL's Planning Approach and Key Planning Assumptions

Q. Please briefly describe FPL's approach to evaluating what role DSM should play 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). A copy of the IRP process write-up which appeared in the 1998 Site Plan is presented in Document No. 1. FPL believes that an integrated resource planning 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 to earn a place in the resource plan.

Q. Did the 1998 IRP work differ from the IRP work which was carried out in the last few years?

A. Yes, but only in regard to certain starting assumptions. The same basic IRP process has been used by FPL since late 1993. At the start of each annual IRP effort, a number of assumptions and projections are updated. Document Nos. 2 and 3 present, respectively, two of the key projections which were used in the 1998 IRP work: the load/energy forecast and the fuel cost forecast.

During the last few years, FPL's IRP work assumed that the level of DSM through the year 2003 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 during those years 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, it was not appropriate to continue to view predetermined DSM levels over a number of years as a "given".

Consequently, the 1998 IRP work assumed that only currently planned DSM additions for 1999 and 2000 were a given. From examining the schedule for this docket's completion, it was assumed that much of 1999 would pass before new DSM goals were set and that much, if not all, of the year 2000 would then be needed to gain approval of new/revised DSM programs and their implementation plans, train FPL's DSM staff in the new parameters of the programs, and allow participating contractors time to make necessary adjustments for new/revised DSM programs. Therefore, FPL's 1998 IRP work started with the assumption that the currently planned DSM for 1999 and 2000 would be viewed as a given. A corresponding assumption, that <u>no</u> additional DSM would be viewed as a given beyond the year 2000, was also made. Therefore, DSM would have to compete to earn a post-2000 role in FPL's resource plan.

Q. What were the other key planning assumptions utilized in the 1998 IRP work?

A. There were two other key assumptions which affected the analysis of DSM. The first of these involved commitments FPL made in 1998 to repower existing power plants at two of its existing power plant sites. FPL's <u>1998 Site Plan</u> introduced FPL's plans to repower both existing steam units at FPL's Ft. Myers plant site, and two of the three existing steam units at FPL's Sanford plant site. Subsequent to the release of the <u>1998 Site Plan</u>, FPL committed to both of these repowering projects which represent significant capacity additions (over 1,700 incremental MW in total) to the FPL system.

The repowered units are scheduled to come in-service in January, 2002, and January, 2003, respectively. In addition, the early installation (as part of the repowering work) of combustion turbines at both of these sites in the year preceding each project's in-service date will also add significant capacity to the system during these two preceding years (2001 and 2002) as well. This is due to the fact that the combustion turbines will be able to operate in a stand-alone, simple cycle mode prior to their connection to heat recovery steam generators to form the repowered combined cycle unit.

The second of these key assumptions involved the relative accuracy of load forecasts for different time periods. The general assumption was that the accuracy of most forecasts generally tends to diminish the further out in time the forecast attempts to predict. In its 1998 IRP work, FPL applied this general assumption to its forecast of peak loads and assumed, for example, that forecasts of peak loads 6 years out would be less accurate than forecasts of peak loads 3 years out.

The manner in which FPL incorporated this assumption was to first determine what FPL's resource needs were projected to be assuming that the accuracy of the load forecast was unchanged regardless of how far into the future the forecast reached (i.e., by first ignoring the assumption that load forecast accuracy diminishes over time). Then, for years which were more than 3 or 4 years out from 1998, identify the year(s) for which reserve margin declined so that it neared the 15% criterion level. For any year with these characteristics, an additional resource need for that year was assumed to exist. (For the 10-year time frame of 2000-2009 which this docket addresses, only one year, 2005, was projected to have these characteristics. FPL addressed this by assuming a 350 MW resource need for 2005 and inserting this additional need in its system reliability analysis.)

Q. What are the potential effects which these two assumptions might have on the role which DSM could have in FPL's resource plan?

A. The potential effects of these two assumptions are varied both in terms of the magnitude and timing of DSM's potential role in the resource plan. The commitment to repower the existing Ft. Myers and Sanford units adds enough capacity so that <u>no</u> additional resource option, DSM or supply, is needed in 2001 through 2004 to meet reliability needs for those years. Therefore, the effect of this assumption is to reduce DSM's potential role for those years.

However, the decision to address uncertainty concerning longer-term forecasted peak loads by inserting an additional resource need in 2005 both accelerates the timing of resource needs after 2004 and increases the magnitude of these needs. The potential role for DSM is, therefore, both accelerated and enlarged after 2004. In addition, if DSM is determined to be cost-effective in sufficient quantities to displace capacity additions by 2005 or 2006, it will be necessary to begin signing up DSM participants a number of years earlier than that due to the fact that hundreds of MW of DSM cannot be signed up and installed in a year or two. Thus, additional DSM could begin to appear in the resource plan prior to 2005 in order to achieve sufficient DSM by 2005 or 2006 to displace a new generating unit.

Q. Could DSM have displaced either of FPL's two repowering projects?

A. No. It is not possible for DSM to displace them. This is most easily seen by considering the amount of additional cost-effective DSM which would have been needed in a very short time to displace either of these near-term capacity additions. For example, as discussed in FPL's 1998 Site Plan, FPL faced both a system-wide and a region-specific resource need by 2002 which is going to be met by the Ft. Myers repowering project. In regard to the regional need only, approximately 400 MW of new generation capacity or equivalent DSM were needed by January, 2002, in a very specific region (the Lee and Collier counties area) in order to satisfy a transmission-driven Winter resource need and avoid the construction of a 500 KV line from Florida's east coast to this region. It would take many years for DSM to supply such a large amount of MW cost-effectively (or otherwise) in a two-county area. Thus, it was not possible to address this resource need with DSM.

Similarly, although the resource need which the Sanford project fills is solely a system-wide need, sufficient cost-effective DSM could not be implemented in time to address this need either. (The amount of cost-effective DSM which is potentially achievable each year for the 2001 through 2009 time period is discussed later in my testimony.)

Q. How would you summarize the effects of this initial assumption-setting stage of the 1998 IRP work as it relates to DSM goal setting?

A. In regard to the setting of DSM goals for the years 2000 through 2009, the effects of the assumptions which were set can be summarized as follows:

1) Currently planned DSM implementation levels for the years 1999 and 2000 were taken as a given due to the time necessary to complete this docket, approve new/revised DSM programs, and begin to implement those programs. Consequently, the currently planned DSM level for the year 2000 will become FPL's DSM goal for 2000. The 1998 IRP work then sought to set new DSM goals for the remaining nine-year period of 2001 through 2009.

2) FPL's commitment to repower existing power plants at two sites means that no additional resources, supply or DSM, are needed in the 2001 through 2004 time frame to meet reliability needs for those years. This limits the role which DSM could potentially play

during those years.

3) Conversely, FPL's decision to increase its projected resource needs for 2005 above what would otherwise be reflected in its 1998 planning work increases and accelerates the role which DSM could potentially play in addressing resource needs beyond 2004. Furthermore, since it takes a number of years to accumulate large amounts of DSM MW, this means that additional DSM might have to be signed up prior to 2005 in order to address 2005 – on needs.

II. Cost-Effectiveness Screening of DSM Options and the Determination of DSM's Achievable Potential

Q. What was the nature of the next DSM-specific work undertaken in the 1998 IRP work?

A. The next DSM-specific work involved the determination of how much DSM was potentially cost-effective and achievable in each year for the 2001 through 2009 time frame. Once this information is known, it is possible to begin to accurately determine what role DSM might play in the resource plan.

Q. How does FPL determine how much DSM is potentially cost-effective and achievable?

A. FPL makes this determination in 3 basic steps. In the first step, "stripped down" DSM options are analyzed versus the likely supply option they would have to displace to earn a role in the resource plan. The information supplied for these "stripped down" DSM options includes all of the normal information (i.e., kw reduction per participant, kwh reduction per participant, administrative costs per participant, etc.) <u>except</u> for an incentive cost per participant. The intent of this analysis is to determine whether a DSM option is cost-effective even <u>without</u> an incentive payment.

If a DSM option is <u>not</u> cost-effective even without any incentive payment, it is deemed not to have "survived" this cost-effectiveness screening and is dropped from further consideration in the IRP process. If a DSM option <u>is</u> cost-effective without an incentive payment, a determination is made as to how large an incentive payment can be made before the DSM option is no longer cost-effective. These analyses are carried out using the Commission's approved cost-effectiveness methodology and utilize the Rate Impact Measure (RIM) test.

The second step involves using the incentive level information determined in the first step to then develop projections of how many participants (or how many kw) the market potentially could provide each year for each surviving DSM option at a selected incentive level. (The selection of an incentive level for a DSM option involves the use of the Participant's cost-effectiveness test. Mr. Brandt's testimony addresses this second step which is carried out by FPL's Marketing Department.)

In the third and final step, the DSM options are also evaluated to see if there are any non-economic factors which could further impact the achievable potential of an option. (This step is carried out by the Resource Assessment & Planning Department and will be discussed later in my testimony.)

Q. In the first of these three steps, how did FPL determine what the "likely supply option" was which DSM might displace?

A. In order to perform the cost-effectiveness screening of the "stripped down" DSM options, it was necessary to project what type of new generating units would be added to FPL's system absent any DSM and when those units would likely be added. In regard to the "what type" question, early 1998 projections of supply option cost and performance indicated that natural gas-fired combined cycle (CC) units would almost certainly be FPL's supply option of choice for most of the next decade. Therefore, the assumption was made at this point in the 1998 IRP work that DSM would most likely compete with CC capacity. (This assumption was proven correct later in the 1998 IRP work when FPL constructed its

Supply Only resource plan which will be discussed later in my testimony.)

The next question to answer was "when" these new CC units might be added. In order to determine this, a system reliability analysis was performed using reliability criteria of 0.1 day per year loss-of-load-probability (LOLP), a minimum Summer reserve margin of 15%, and a minimum Winter reserve margin of 15%. The results of this system reliability analysis, which incorporated the previously discussed addition of a 350 MW need in 2005 due to load forecast uncertainty, are presented in Document No. 4.

The results shown in Document No. 4, plus the assumption that all of the new generating units that would be added during this time frame would be CC units, led to the conclusion that one new CC unit (of approximately 400 MW) would likely be added each year starting in 2005.

Since at this stage of the analysis FPL did not yet know exactly how much achievable potential DSM would be cost-effective each year, an estimate had to be made in order to determine what year of capacity need shown in Document No. 4 might be targeted by DSM. For this purpose, FPL assumed that as much as 100 MW of DSM might be cost-effective and achievable each year. This assumption was based on several considerations including: the annual levels of DSM currently being achieved, the projected cost of new generating options at the time the current goals were set versus the current (and lower) projected cost of new generating options, and DSM cost-effectiveness analyses which were conducted in 1997 when FPL last modified its DSM programs.

Assuming that a maximum of 100 MW of DSM might be signed up each year means that it would take 3-to-4 years to accumulate enough new DSM capability to displace a new 400 MW CC unit that would otherwise be needed. This meant that enough DSM, if started in 2001, might be signed up in time to compete with new CC units which would otherwise come in-service first in 2005 and then again in 2008. Therefore, FPL's cost-effectiveness screening of the "stripped down" DSM options was first carried out versus CC capacity projected to come in-service in 2005. FPL assumed that DSM signed up prior to 2005 competed with this CC capacity. Next, FPL did additional cost-effectiveness screening versus CC capacity projected to come in-service in 2008. FPL assumed that DSM signed up in 2005 through 2007, plus some DSM signed up in the 2001 – 2004 period which was in excess of the amount needed to potentially displace a 2005 unit, competed with this CC capacity.

Q. What was the result of this cost-effectiveness screening of DSM?

A. Of approximately 250 initial DSM options submitted for analysis, 47 DSM options, in their "stripped down" mode, were found to be cost-effective versus the CC capacity in the economic screening process described above. FPL's Marketing Department then reexamined these surviving 47 options in order to determine optimal incentive levels and what the achievable potential for each option was based on the selected incentive level. (As previously mentioned, Mr. Brandt's testimony addresses the work undertaken in this step of this analysis.)

Q. Earlier you referred to a third step in this analysis. Was such a step carried out in the 1998 IRP work, and, if so, what were the results?

A. FPL did carry out an analysis as part of the 1998 IRP work to see if there were any non-economic factors which could impact the achievable potential of DSM options. This analysis was directed at FPL's load control programs and was a continuation of similar analyses FPL has conducted in the past. The objective was to see if FPL was nearing 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. The concept is best understood by first visualizing the shape of a utility's peak day load and then visualizing 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 as shown in Document No. 5 with the peak hour's load at the very top of the curve.

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 the utility's system sees 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.

In order to lower the system's peak load, a utility typically initiates load control <u>prior to</u> what its peak load hour would have been, and continues it for a time past what the peak load hour would have been, in order 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 is illustrated in Document No. 6.

In the Document No. 6 depiction, load control is implemented for approximately 3 hours to achieve a desired 100 MW load reduction. Note that it is necessary to implement load control for this long in order 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 shape to the right-hand side (which is a time period 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 certain 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 that 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. 7.

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 the fact 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" <u>can</u> be increased by either increasing the tariff limits to control 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 in order to achieve a desired reduction and the tariff limit of control 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 either 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).

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 another. 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 "spikey" appearance). All else equal, this means that FPL could utilize more 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 to 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. FPL utilizes linear programming techniques to perform this analysis. The basic steps for this analysis include the following:

1) Develop a 15-minute interval projection of a future peak day load shape. (For example, develop such a projection for the August, 2002, 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 included projections for its residential and Commercial/Industrial load control programs in the analysis.)

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 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 available 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 theorectical reduction versus the linear programming result. (In our example, did 100 + 10 = 110 participants x 1kw/participant yield 110 kw?)

Once the point has been reached at which additional increments of load control do <u>not</u> yield the projected theoretical results (for example, 110 participants yielded <u>less</u> than 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.

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

A. The basic result is that FPL now appears to be <u>nearing</u> the physical limit of usable load control given current projections of future load shapes, demand reductions, payback, and tariff restrictions. FPL's analysis showed that the physical limit in regard to Summer peak was more restrictive than in regard to Winter peak. Consequently, FPL's analysis concentrated on the usable amount of load control "versus" FPL's projected Summer peak loads.

The analysis looked at how much additional load control was usable in two-year increments (i.e., versus projected Summer peak day loads for 2002, 2004, 2006, 2008, and 2010). These analyses showed that the amounts of additional load control which were usable were declining over time. The analysis showed that FPL could add approximately 80 MW of additional load control by 2002, another 40 MW by 2004, another 35 MW by 2006, an additional 35 MW by 2008, and an increment of 20 more MW by 2010 and still have all of FPL's total load control be usable versus the projected Summer peak loads.

These incremental values of usable load control represent a significant decrease from the amount of load control FPL is currently signing up per year. The sum of these usable incremental amounts is 210 MW by 2010. This equates to approximately 20 MW/year of total incremental load control capacity. By comparison, FPL has signed up approximately 60 MW per year of residential load control alone over the last few years.

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

A. In terms of increasing the amount of usable load control, adding incremental load control that either has relatively long control durations and/or has little or no payback (such as pool pump control or Commercial/Industrial load control) is most helpful.

Q. How did FPL then utilize the results of these analyses in its 1998 IRP work?

A. FPL used the above-mentioned increments of usable load control as its maximum achievable potential for all of the load control programs combined. This served to lower the amount of load control achievable potential (and, correspondingly, also lowered the achievable amount of total DSM) that otherwise would have been used in the 1998 IRP work.

Q. After all 3 steps of determining DSM's achievable potential were completed, how much potential cost-effective DSM by year was projected?

A. For the 9 years analyzed, 2001 through 2009, approximately 70 MW per year of DSM were projected to be the annual cost-effective potential amount. (Note that the 70 MW value is an "at the meter" value. The corresponding "at the generator" value after accounting for line losses is approximately 10% higher.)

Q. Please summarize the results of the work designed to determine the achievable potential for cost-effective DSM for the years 2001 through 2009.

A. The key results of this work can be summarized as follows:

1) FPL analyzed approximately 250 DSM options, assuming zero incentive payments for each, to determine which would be cost-effective versus combined cycle capacity in the period beyond 2004. The Commission's approved cost-effectiveness methodology was utilized to perform these evaluations which were based on the RIM test. Of these options, 47 survived this initial screening and were carried forward in the rest of the analysis.

2) For each of these options, FPL determined an optimum incentive level using the Participant's test. The achievable potential for each option was then developed based on the selected incentive level.

3) For the load control options, an additional analysis was performed to determine how much load control was usable on the FPL system. These values were lower than the achievable potential values that otherwise would have been developed and were thus used as the maximum achievable potential for these options.

4) These efforts combined to show a projected annual potential of approximately 70 MW of cost-effective DSM for the 9 years of 2001 through 2009.

III. Development and Comparison of Resource Plans w/ and w/o DSM

Q. How did FPL evaluate whether the approximately 70 MW of DSM per year were truly cost-effective?

A. In order to test whether all or part of this potentially achievable DSM was really cost-effective, it was necessary to analyze DSM within the context of a resource plan. This approach allows one to determine two things. First, what would the implementation of this DSM accomplish in terms of displacing new generating units that otherwise would be built? Second, would this displacement of new units by DSM be cost-effective when comparing resource plans both with and without DSM?

In order to address the first item, FPL constructed a Supply Only resource plan based on the system resource needs which were shown in Document No. 4. This resource plan included the DSM projected to be signed up through the end of the year 2000, but with no additional DSM after that year. In this plan, all of FPL's resource needs were met by adding new generating units. This Supply Only resource plan, which was developed using the EGEAS (Electric Generation Expansion Analysis System) computer model developed by Stone & Webster Management Consultants, Inc., is presented in Document No. 8.

In order to fairly compare the economics of the Supply Only resource plan and a second resource plan which utilizes DSM, it is necessary to examine the impacts on system rates of the two plans. FPL performs this comparison by calculating a system levelized average rate based on each plan. This calculation for the Supply Only resource plan is presented in Document No. 9.

As shown in Document No. 9, the system average levelized rate for the Supply Only resource plan is 8.30 cents/kwh. If a resource plan which includes all or part of the DSM achievable potential which was earlier identified can be constructed which results in a lower system average levelized rate, then the inclusion of the 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. 8 and the achievable potential DSM levels for each year which had been identified. The objective was to construct a resource plan which included this DSM which had comparable reserve margins and LOLP values as that of the Supply Only resource plan.

In order to accomplish this, three things became apparent. First, FPL could construct such a resource plan if it utilized 100% of the DSM that had been identified as potentially cost-effective for the 2001 through 2008 time frame. (This meant that FPL's normal practice of utilizing linear programming techniques to select only the most cost-effective DSM options would not be needed for this case since <u>all</u> of the identified achievable potential DSM for each year would be used.)

The second item which became apparent was that the inclusion of all of the identified potentially achievable DSM from 2001 through 2008 was sufficient to displace new combined cycle units that otherwise would have come in-service in 2005 and 2009.

The third thing which became apparent was that the approximately 70 MW of DSM which was potentially achievable in the year 2009 was not really needed since it, on its own, was not of sufficient magnitude to displace a new generating unit.

Q. What did FPL decide to do about these 70 MW of DSM that could be signed up in 2009?

A. FPL believes that the technically <u>correct</u> action to take would be to leave out this DSM in 2009, since it alone isn't large enough to displace a unit. In other words, FPL would propose zero DSM MW as its goal for the last year in question (2009).

However, when FPL proposed a similar DSM goal (zero MW for the last 3 years) in its 1994 DSM Goals filing, it was rejected, and FPL's goals for those 3 years were set at the level of the last year immediately preceding those 3 years. Recognizing that a similar outcome is likely in this year's proposal, FPL chose to simply include the full 70 MW of achievable potential DSM for 2009 in its With DSM resource plan.

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

A. This With DSM resource plan is presented on the right-hand side of Document No. 10 which also includes the Supply Only resouce plan information previously presented in Document No. 8.

It is evident from examining Document No. 10 that the two resource plans have Summer reserve margins which are approximately the same. A similar comparison of Winter reserve margins and annual LOLP values was also made, and the results are presented in Document No. 11. As shown in Document Nos. 10 and 11, the two plans are generally comparable in regard to system reliability with first one plan and then another alternately taking an edge in regard to a particular reliability criterion due to the timing and nature of the resource being added in that plan.

The system average levelized rate for the With DSM resource plan was calculated to be 8.29 cents/kwh. This calculation is presented in

Document No. 12.

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

A. Since both of the two resource plans would provide both comparable and sufficient system reliability, the With DSM plan should be selected as FPL's integrated resource plan since it provides a lower system average levelized rate. FPL will present this resource plan, with its underlying DSM levels, as FPL's official resource plan in its <u>1999 Ten Year Power Plant Site Plan</u> later this year. These underlying DSM levels are being proposed in this docket as the new DSM Goals for FPL for the 2000 through 2009 time frame.

IV. Summary of Analyses and a Discussion of FPL's Proposed DSM Goals

Q. How would you summarize the 1998 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 in order to determine how much DSM was cost-effective to add in the 2000 through 2009 time frame. This is the correct approach to take in order to make such a determination. Economic impacts were determined on a system

rate basis which is the correct and equitable way to compare supply and DSM options which have such different effects on a utility system.

2) FPL included the appropriate key assumptions in its analyses regarding both DSM implementation plans that have already been made and supply options (i.e., repowering projects) to which FPL has already committed.

3) The initial economic screening of DSM options was performed using an appropriate tool, the Commission's approved cost-effectiveness methodology, and versus appropriate types of supply options (i.e., new combined cycle capacity). Consequently, this screening allowed FPL to determine optimal incentive payments and potentially achievable market levels for each option. Additional analyses of load control options further refined (and lowered) the achievable market potential for these options.

4) Both the Supply Only and With DSM resource plans were designed to provide adequate system reliability, and the two plans are generally 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 should propose this amount of DSM as its new DSM goals for the 2000 through 2009 time frame.

Q. Would you say that the level of DSM included in FPL's new proposed DSM goals is appropriate, even if this level is less than what is called for in FPL's current DSM goals?

A. Yes. I believe that a knowledgeable, unbiased observer who was familiar with how FPL's current DSM goals were set in 1994, and who looked at the assumptions going into the 1998 IRP work, would have almost certainly concluded that FPL would propose lower DSM goals than those which currently exist. I believe such an observer would reach this conclusion for three primary reasons.

First, FPL's commitment to capacity additions through the repowering projects at its Ft. Myers and Sanford sites reduces the need for additional resource additions of any kind, DSM or other supply options, during the ten year period. This can be quantified by comparing the cumulative resource need shown in Document No. 4 (1,905 MW) to the corresponding "table" (actually, Figure 4) in FPL's Cost-Effectiveness Goals Results Report filed for the last DSM Goals docket in 1994. This showed that FPL's projected resource need then was 2,290 MW for the same corresponding period (i.e., the last 9 years of the 10-year goal-setting period). Thus, the total resource need for which DSM is now competing is smaller by almost 400 MW, or close to 20%, when compared to the resource need which existed when the current DSM goals were set.

Second, as previously discussed, FPL believes that it now needs to "put a cap" on how much incremental load control it adds during the next 10 years, since it is reaching the physical limit for how much of the current load control programs will be fully usable on its system. FPL's load control programs are significant contributors to FPL's current DSM plan, with about 30% of FPL's current 10-year goals (or about 500 MW of the 1,500 MW goals total) scheduled to be met by the load control programs. FPL can no longer count on load control to be such a large contributor to its resource plan. The total achievable potential for all of FPL's load control programs is now about 200 MW. This drop of 300 MW of load control potential further reduces the role which DSM can play in the resource plan.

Third, and most importantly, DSM's "opponent" in regard to earning a role in the resource plan has gotten significantly stronger (i.e., new generating units are now projected to be significantly less expensive to construct and operate) since the 1994 time frame when DSM's current goals were set. Document No. 13 presents a comparison of 1994 versus 1998 projections for certain cost and performance values for new combined cycle units. One area in which performance projections have significantly improved is unit efficiency or heat rate. As shown in Document No. 13, 1994 projections of new combined cycle heat rates were approximately 7,200 BTU/kwh. Current projections of heat rates for new combined cycle units are approximately 6,100 BTU/kwh. Partly as a result of these gains in efficiency, total annual costs for similar sized combined cycle units using 1998 assumptions are projected to be approximately 35% lower on average than total annual costs using 1994 assumptions. This lowering of projected supply option costs forces DSM incentives to be reduced from what they were in 1994 in order for DSM to remain cost-effective. The lower incentive payments then directly result in projections of lower achievable market potential for DSM and a reduced role in the resource plan.

These three factors, committed capacity additions which fill FPL's early resource needs, a reduced role for load control, and lower achievable DSM market potential for all DSM options due to more economical generation technology being available, lead to a logical conclusion that FPL's new proposed DSM goals <u>should be</u> lower than what was proposed in 1994.

Q. Does this conclude your testimony?

A. Yes.

Document No. 1

Overview of FPL's IRP Process
(from the 1998 Ten Year Site Plan)

III. Projection of Incremental Resource Additions

III.A. FPL's Resource Planning:

FPL has developed an integrated resource planning (IRP) process in order to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of potential new power plants, the primary subject of this document, is determined as part of this work. This section discusses how FPL applied this process in its 1997 planning work.

Four Fundamental Steps of FPL's Resource Planning:

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

Step 1: Determine the magnitude and timing of FPL's resource needs,

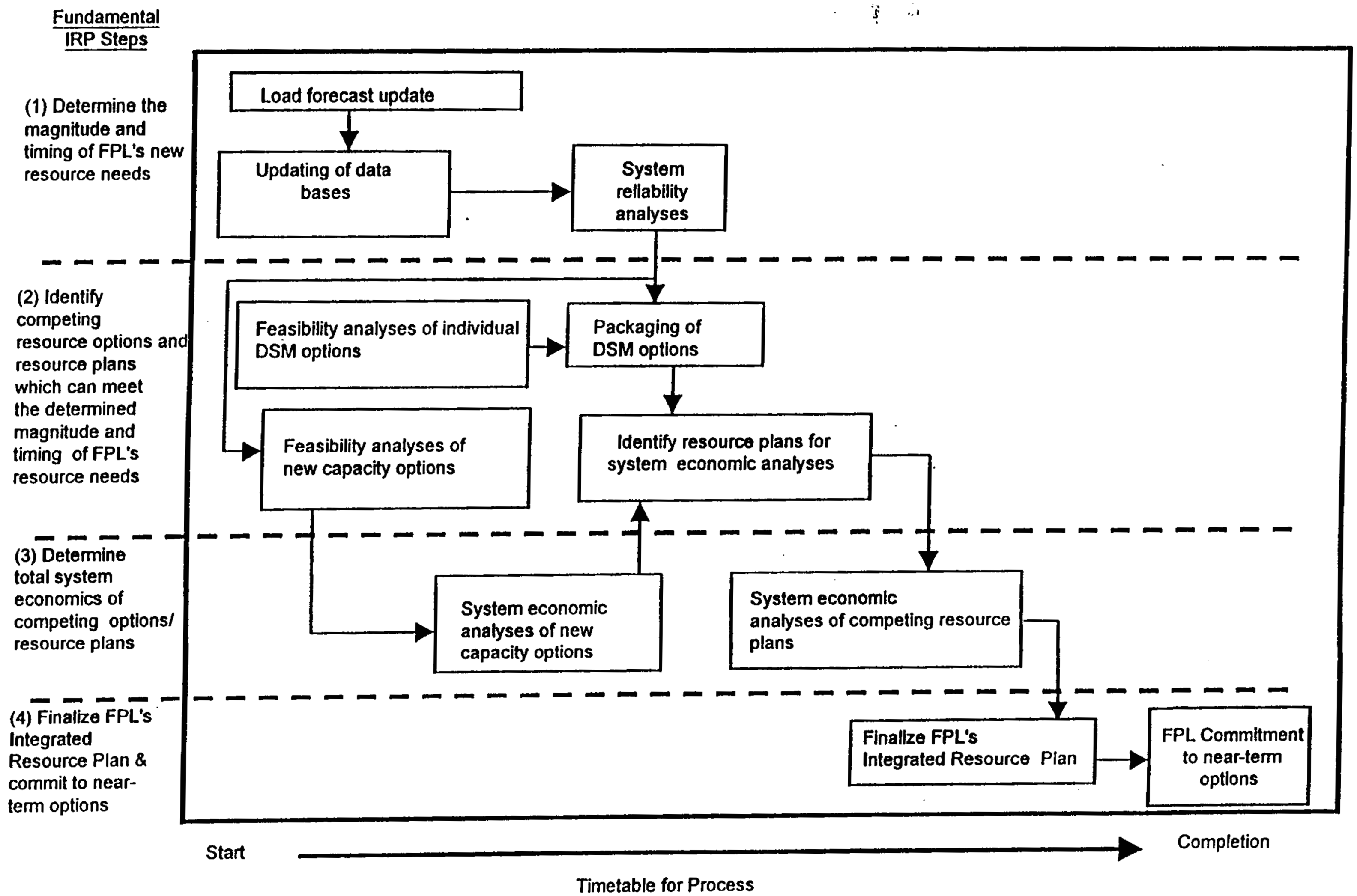
Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e.; identify competing options and resource plans,

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 commit, as needed, to near-term options.

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

Overview of FPL's IRP Process



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

Figure III.A.1

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

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

Step 1 starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding load forecasts, but also with other information as well. This information is used in many of the fundamental steps in resource planning. Examples of this new information include delivered fuel price projections and current financial and economic assumptions. In 1997, FPL's DSM MW goals were added to the reliability analysis database as an "already-committed-to" resource.[1] Therefore, the 1997 reliability analyses were primarily concerned with identifying the timing and magnitude of needed new capacity options.

The first place much of this updated information is used is in the analyses which provide the desired result of the 1st fundamental step: the determination of the magnitude and the timing of FPL's resource needs. This determination is accomplished by system reliability analyses which are typically based on a dual planning criteria of a minimum Summer reserve margin of 15% and a maximum loss-of-load probability (LOLP) of 0.1 days/year. These criteria are commonly used throughout the utility industry. In addition to these two reliability criteria which FPL has traditionally utilized, FPL also used a third reliability criterion in 1997: a 15% Winter reserve margin criterion. This third criterion was used in FPL's 1997 planning work due to concern regarding reserves available during extreme Winter peak loads.[2]

Historically, two types of methodologies, deterministic and probabilistic, have been employed in system reliability analyses. The calculation of excess firm capacity around the annual system peak (reserve margin) is the most common deterministic method and this relatively simple calculation can be performed on a spreadsheet. It provides an indication of how well a generating system can meet its native load during peak periods. However, deterministic

[1] This represents a modification to FPL's basic IRP process. However, FPL's DSM Goals for the years 1994 through 2000 were directly derived from the application of FPL's basic IRP process in late 1993/early 1994.

[2] FPL will continue to monitor this concern and make appropriate adjustments as needed to provide reliable service.

methods do not take into account probabilistic events such as: unit availability, unit size (i.e., two 50 MW units with a 90% availability are more valuable in regard to utility system reliability than is one 100 MW unit with a 90% availability), 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 will be able to meet its demand (i.e., a measure of how often load will 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 "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. This analysis requires a more complicated calculation methodology than does reserve margin analysis.

The end result of the first fundamental step of resource planning is a projection of how many MW are needed to maintain system reliability and of when the MW are needed. This information is used in the second fundamental step: identifying resource options and resource plans which can meet the determined 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. FPL's Power Generation Business Unit initially analyzes new capacity options. During this step, feasibility analyses of new capacity options are carried out to determine which new capacity options appear to be the most competitive on FPL's system. These analyses also establish capacity size (MW) values, projected construction / permitting 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 capacity options so that the timing and magnitude of

FPL's new resource needs are met. The creation of these competing resource plans is typically carried out using dynamic programming techniques.

Therefore, at the conclusion of the second fundamental resource planning step in 1997, a number of different combinations (i.e., resource plans) of new capacity options of a magnitude and timing necessary to meet FPL's resource needs (which would be needed after the DSM MW goals were assumed to be met) were identified. These resource plans were then compared on an economic basis.

Step 3: Determining the Total System Economics:

At the completion of the fundamental steps 1 & 2, the most viable new capacity options have been identified, and these capacity options have been combined into a number of resource plans. The stage is set for comparing the system economics of these resource plans. FPL combines the new capacity options into resource plans and performs the economic analyses of those plans using the EGEAS (Electric Generation Expansion Analysis System) computer model from Stone & Webster Management Consultants, Inc.

The economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of the competing resource plans is the competing resource plans' 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, since in 1997 the DSM goals through the year 2003 were taken as "a given", the economic analyses were comparisons of competing capacity options. Since a utility's total kwh sales do not vary when comparing new capacity options, the capacity options which yield the lowest cost also yield the lowest rates. Therefore, for the 1997 resource planning work, these resource plans were compared on the basis of lowest cost (i.e., cumulative present value of revenue requirements.)

At the conclusion of the analyses carried out in Step 3, a determination of FPL's preferred resource plan was made.

Step 4: Finalizing FPL's 1997 Resource Plan:

The results of the previous three fundamental steps' activities were evaluated by FPL management and a decision was made as to what FPL's 1997 resource plan would be. This plan is presented in the following section.

Document No.2

Peak Load & Net Energy for Load (NEL) Projection: 2001 - 2009

Peak Load & Net Energy for Load (NEL) Projection: 2001 - 2009

	Peak Load		
Year	Summer MW	Winter MW	NEL GWH
2001	17,865	18,615	94,812
2002	18,129	19,025	96,822
2003	18,469	19,426	98,696
2004	18,818	19,816	100,633
2005	19,170	20,204	102,467
2006	19,532	20,579	104,325
2007	19,901	20,953	106,210
2008	20,245	21,328	108,171
2009	20,579	21,715	110,355

Document No. 3

1998 Fuel Cost Forecast

FPL 1998-2027 LONG TERM BASE CASE FOSSIL FUEL PRICE AND NATURAL GAS AVAILABILITY FORECAST
NATURAL GAS AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY

		********************FIRM TRANSPORTATION SERVICE********************					
MONTH	NON-FIRM TRANSPORT SERVICE	PHASE II FIRM GAS SUPPLY GAS SUPPLY TAKE OR PAY MINIMUM	(SEE NOTE 1) MAXIMUM	PHASE III FIRM GAS SUPPLY (TAKE OR PAY) (SEE NOTE 2) FIXED	PHASE II NON-FIRM GAS SUPPLY (SEE NOTE 1) MAXIMUM	PHASE III NON-FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	TOTAL (MAXIMUM) NATURAL GAS AVAILABILITY
APRIL 1998	245	32	200	100	80	100	725
MAY	90	126	330	100	100	100	720
JUNE	90	126	330	100	100	100	720
JULY	90	126	330	100	100	100	720
AUGUST	90	126	330	100	100	100	720
SEPTEMBER	90	126	330	100	100	100	720
OCTOBER	245	32	200	100	80	100	725
NOVEMBER	245	32	200	100	55	100	700
DECEMBER	245	32	200	100	55	100	700
JANUARY 1999	235	32	200	100	55	100	690
FEBRUARY	235	32	200	100	55	100	690
MARCH	235	32	200	100	55	100	690
APRIL	235	32	200	100	80	100	715
MAY	80	126	330	100	100	100	710
JUNE	80	126	330	100	100	100	710
JULY	80	126	126	100	304	100	710
AUGUST	80	126	126	100	304	100	710
SEPTEMBER	80	126	126	100	304	100	710
OCTOBER	235	32	32	100	248	100	715
NOVEMBER	235	32	32	100	223	100	690
DECEMBER	235	32	32	100	223	100	690
JANUARY 2000	225	32	32	100	223	100	680
FEBRUARY	225	32	32	100	223	100	680
MARCH	225	32	32	100	223	100	680
APRIL	225	32	32	100	248	100	705
MAY	70	126	126	100	304	100	700
JUNE	70	126	126	100	304	100	700
JULY	70	126	126	100	304	100	700
AUGUST	70	126	126	100	304	100	700
SEPTEMBER	70	126	126	100	304	100	700
OCTOBER	225	32	32	100	248	100	705
NOVEMBER	225	32	32	100	223	100	680
DECEMBER	225	32	32	100	223	100	680
1995							638
1996							594
1997							624
1998							656
1999	170	71	161	100	171	100	703
2000	160	71	71	100	261	100	693

		********************FIRM TRANSPORTATION SERVICE********************					
MONTH	NON-FIRM TRANSPORT SERVICE	PHASE II FIRM GAS SUPPLY GAS SUPPLY TAKE OR PAY MINIMUM	(SEE NOTE 1) MAXIMUM	PHASE III FIRM GAS SUPPLY (TAKE OR PAY) (SEE NOTE 2) FIXED	PHASE II NON-FIRM GAS SUPPLY (SEE NOTE 1) MAXIMUM	PHASE III NON-FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	TOTAL (MAXIMUM) NATURAL GAS AVAILABILITY
JANUARY 2001	215	32	32	100	223	100	670
FEBRUARY	215	32	32	100	223	100	670
MARCH	215	32	32	100	223	100	670
APRIL	215	32	32	100	248	100	695
MAY	60	126	126	100	304	100	690
JUNE	60	126	126	100	304	100	690
JULY	60	126	126	100	304	100	690
AUGUST	60	126	126	100	304	100	690
SEPTEMBER	60	126	126	100	304	100	690
OCTOBER	215	32	32	100	248	100	695
NOVEMBER	215	32	32	100	223	100	670
DECEMBER	215	32	32	100	223	100	670
JANUARY 2002	225	32	32	100	223	180	760
FEBRUARY	225	32	32	100	223	180	760
MARCH	225	32	32	100	223	180	760
APRIL	225	32	32	100	248	180	785
MAY	70	126	126	100	304	180	780
JUNE	70	126	126	100	304	180	780
JULY	70	126	126	100	304	180	780
AUGUST	70	126	126	100	304	180	780
SEPTEMBER	70	126	126	100	304	180	780
OCTOBER	225	32	32	100	248	180	785
NOVEMBER	225	32	32	100	223	180	760
DECEMBER	225	32	32	100	223	180	760
JANUARY 2003	215	32	32	100	223	180	750
FEBRUARY	215	32	32	100	223	180	750
MARCH	215	32	32	100	223	180	750
APRIL	215	32	32	100	248	180	775
MAY	70	126	126	100	304	180	780
JUNE	70	126	126	100	304	180	780
JULY	70	126	126	100	304	180	780
AUGUST	70	126	126	100	304	180	780
SEPTEMBER	70	126	126	100	304	180	780
OCTOBER	215	32	32	100	248	180	775
NOVEMBER	215	32	32	100	223	180	750
DECEMBER	215	32	32	100	223	180	750
2001	150	71	71	100	261	100	683
2002	160	71	71	100	261	180	773
2003	155	71	71	100	261	180	767

NOTE 1: FOR PURPOSES OF ANALYSIS, FROM MARCH, 1995 THROUGH JULY, 2005, ASSUME THAT UP TO 332 MILLION CUBIC FEET PER DAY OF THE PHASE II TRANSPORTATION CAPACITY WILL BE AVAILABLE TO FPL. FOR THESE VOLUMES, ASSUME THE TRANSPORTATION DEMAND CHARGE IS A SUNK COST. FROM AUGUST, 2005 FORWARD, ASSUME THAT THESE PHASE II VOLUMES ARE STILL AVAILABLE, HOWEVER, 100% OF THE DELIVERED NATURAL GAS PRICE IS VARIABLE. (I.e. THE TRANSPORTATION DEMAND CHARGE IS NOT TAKE OR PAY) UNTIL A DECISION IS MADE ON THE VOLUME OF PHASE II TRANSPORTATION SERVICE FPL WILL COMMIT TO AFTER JULY, 2005. THEREAFTER, THE NEW FIRM TRANSPORTATION DEMAND CHARGE WILL BECOME A SUNK COST.

NOTE 2: FOR PURPOSES OF ANALYSIS, FROM MARCH, 1995 THROUGH FEBRUARY, 2010, ASSUME THAT UP TO 200 MILLION CUBIC FEET PER DAY OF THE PHASE III TRANSPORTATION CAPACITY WILL BE AVAILABLE TO FPL. FOR THESE VOLUMES, ASSUME THE TRANSPORTATION DEMAND CHARGE IS A SUNK COST. FROM MARCH, 2010 FORWARD, ASSUME THAT THESE PHASE III VOLUMES ARE STILL AVAILABLE, HOWEVER, 100% OF THE DELIVERED NATURAL GAS PRICE IS VARIABLE. (I.e. THE TRANSPORTATION DEMAND CHARGE IS NOT TAKE OR PAY) UNTIL A DECISION IS MADE ON THE VOLUME OF PHASE III FIRM TRANSPORTATION SERVICE AND FIRM NATURAL GAS SUPPLY FPL WILL COMMIT TO AFTER FEBRUARY, 2010. THEREAFTER, THE NEW FIRM TRANSPORTATION DEMAND CHARGE WILL BECOME A SUNK COST.

ENERGY MARKETING AND TRADING DIVISION
APRIL, 1998 - EUGENE UNGAR

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FPL 1998-2027 LONG-TERM BASE CASE FOSSIL FUEL PRICE AND NATURAL GAS AVAILABILITY FORECAST
NATURAL GAS AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY

	****FIRM TRANSPORTATION SERVICE****						
MONTH	NON-FIRM TRANSPORT SERVICE	PHASE II FIRM GAS SUPPLY GAS SUPPLY TAKE OR PAY MINIMUM	PHASE II FIRM GAS SUPPLY (SEE NOTE 1) MAXIMUM	PHASE III FIRM GAS SUPPLY (TAKE OR PAY) (SEE NOTE 2) FIXED	PHASE II NON-FIRM GAS SUPPLY (SEE NOTE 1) MAXIMUM	PHASE III NON-FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	TOTAL (MAXIMUM) NATURAL GAS AVAILABILITY
JANUARY 2004	210	32	32	100	223	180	745
FEBRUARY	210	32	32	100	223	180	745
MARCH	210	32	32	100	223	180	745
APRIL	210	32	32	100	248	180	770
MAY	65	126	126	100	304	180	775
JUNE	65	126	126	100	304	180	775
JULY	65	126	126	100	304	180	775
AUGUST	65	126	126	100	304	180	775
SEPTEMBER	65	126	126	100	304	180	775
OCTOBER	210	32	32	100	248	180	770
NOVEMBER	210	32	32	100	223	180	745
DECEMBER	210	32	32	100	223	180	745
JANUARY 2005	205	32	32	100	223	180	740
FEBRUARY	205	32	32	100	223	180	740
MARCH	205	32	32	100	223	180	740
APRIL	205	32	32	100	248	180	765
MAY	60	126	126	100	304	180	770
JUNE	60	126	126	100	304	180	770
JULY	60	126	126	100	304	180	770
AUGUST	60	100	100	100	330	180	770
SEPTEMBER	60	100	100	100	330	180	770
OCTOBER	205	32	32	100	248	180	765
NOVEMBER	205	32	32	100	223	180	740
DECEMBER	205	32	32	100	223	180	740
JANUARY 2006	200	32	32	100	223	180	735
FEBRUARY	200	32	32	100	223	180	735
MARCH	200	32	32	100	223	180	735
APRIL	200	32	32	100	248	180	760
MAY	55	100	100	100	330	180	765
JUNE	55	100	100	100	330	180	765
JULY	55	100	100	100	330	180	765
AUGUST	55	100	100	100	330	180	765
SEPTEMBER	55	100	100	100	330	180	765
OCTOBER	200	32	32	100	248	180	760
NOVEMBER	200	32	32	100	223	180	735
DECEMBER	200	32	32	100	223	180	735
2004	150	71	71	100	261	180	762
2005	145	67	67	100	265	180	757
2006	140	60	60	100	272	180	752

	****FIRM TRANSPORTATION SERVICE****						
MONTH	NON-FIRM TRANSPORT SERVICE	PHASE II FIRM GAS SUPPLY GAS SUPPLY TAKE OR PAY MINIMUM	PHASE II FIRM GAS SUPPLY (SEE NOTE 1) MAXIMUM	PHASE III FIRM GAS SUPPLY (TAKE OR PAY) (SEE NOTE 2) FIXED	PHASE II NON-FIRM GAS SUPPLY (SEE NOTE 1) MAXIMUM	PHASE III NON-FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	TOTAL (MAXIMUM) NATURAL GAS AVAILABILITY
JANUARY 2007	195	32	32	100	223	180	730
FEBRUARY	195	32	32	100	223	180	730
MARCH	195	32	32	100	223	180	730
APRIL	195	32	32	100	248	180	755
MAY	50	100	100	100	330	180	760
JUNE	50	100	100	100	330	180	760
JULY	50	100	100	100	330	180	760
AUGUST	50	100	100	100	330	180	760
SEPTEMBER	50	100	100	100	330	180	760
OCTOBER	195	32	32	100	248	180	755
NOVEMBER	195	32	32	100	223	180	730
DECEMBER	195	32	32	100	223	180	730
JANUARY 2008	190	32	32	100	223	180	725
FEBRUARY	190	32	32	100	223	180	725
MARCH	190	32	32	100	223	180	725
APRIL	190	32	32	100	248	180	750
MAY	45	100	100	100	330	180	755
JUNE	45	100	100	100	330	180	755
JULY	45	100	100	100	330	180	755
AUGUST	45	100	100	100	330	180	755
SEPTEMBER	45	100	100	100	330	180	755
OCTOBER	190	32	32	100	248	180	750
NOVEMBER	190	32	32	100	223	180	725
DECEMBER	190	32	32	100	223	180	725
JANUARY 2009	185	32	32	100	223	180	720
FEBRUARY	185	32	32	100	223	180	720
MARCH	185	32	32	100	223	180	720
APRIL	185	32	32	100	248	180	745
MAY	40	100	100	100	330	180	750
JUNE	40	100	100	100	330	180	750
JULY	40	100	100	100	330	180	750
AUGUST	40	100	100	100	330	180	750
SEPTEMBER	40	100	100	100	330	180	750
OCTOBER	185	32	32	100	248	180	745
NOVEMBER	185	32	32	100	223	180	720
DECEMBER	185	32	32	100	223	180	720
2007	135	60	60	100	272	180	747
2008	130	60	60	100	272	180	742
2009	125	60	60	100	272	180	737

NOTE 1: FOR PURPOSES OF ANALYSIS, FROM MARCH, 1995 THROUGH JULY, 2005, ASSUME THAT UP TO 332 MILLION CUBIC FEET PER DAY OF THE PHASE II TRANSPORTATION CAPACITY WILL BE AVAILABLE TO FPL. FOR THESE VOLUMES, ASSUME THE TRANSPORTATION DEMAND CHARGE IS A SUNK COST. FROM AUGUST, 2005 FORWARD, ASSUME THAT THESE PHASE II VOLUMES ARE STILL AVAILABLE, HOWEVER, 100% OF THE DELIVERED NATURAL GAS PRICE IS VARIABLE. (I.e. THE TRANSPORTATION DEMAND CHARGE IS NOT TAKE OR PAY) UNTIL A DECISION IS MADE ON THE VOLUME OF PHASE II TRANSPORTATION SERVICE FPL WILL COMMIT TO AFTER JULY, 2005. THEREAFTER, THE NEW FIRM TRANSPORTATION DEMAND CHARGE WILL BECOME A SUNK COST.

NOTE 2: FOR PURPOSES OF ANALYSIS, FROM MARCH, 1995 THROUGH FEBRUARY, 2010, ASSUME THAT UP TO 200 MILLION CUBIC FEET PER DAY OF THE PHASE III TRANSPORTATION CAPACITY WILL BE AVAILABLE TO FPL. FOR THESE VOLUMES, ASSUME THE TRANSPORTATION DEMAND CHARGE IS A SUNK COST. FROM MARCH, 2010 FORWARD, ASSUME THAT THESE PHASE III VOLUMES ARE STILL AVAILABLE, HOWEVER, 100% OF THE DELIVERED NATURAL GAS PRICE IS VARIABLE. (I.e. THE TRANSPORTATION DEMAND CHARGE IS NOT TAKE OR PAY) UNTIL A DECISION IS MADE ON THE VOLUME OF PHASE III FIRM TRANSPORTATION SERVICE AND FIRM NATURAL GAS SUPPLY FPL WILL COMMIT TO AFTER FEBRUARY, 2010. THEREAFTER, THE NEW FIRM TRANSPORTATION DEMAND CHARGE WILL BECOME A SUNK COST.

ENERGY MARKETING AND TRADING DIVISION
APRIL, 1998 - EUGENE UNGAR

FPL 1998-2027 LONG-TERM BASE CASE FOSSIL FUEL PRICE AND NATURAL GAS AVAILABILITY FORECAST
NATURAL GAS AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY

MONTH	NON-FIRM TRANSPORT SERVICE	FIRM TRANSPORTATION SERVICE: PHASE II FIRM GAS SUPPLY TAKE OR PAY MINIMUM	FIRM TRANSPORTATION SERVICE: PHASE II FIRM GAS SUPPLY (SEE NOTE 1) MAXIMUM	FIRM TRANSPORTATION SERVICE: PHASE III FIRM GAS SUPPLY (TAKE OR PAY) (SEE NOTE 2) FIXED	PHASE II NON-FIRM GAS SUPPLY (SEE NOTE 1) MAXIMUM	PHASE III NON-FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	TOTAL (MAXIMUM) NATURAL GAS AVAILABILITY
JANUARY 2010	180	32	32	100	223	180	715
FEBRUARY	180	32	32	100	223	180	715
MARCH	180	0	0	0	255	280	715
APRIL	180	0	0	0	280	280	740
MAY	35	0	0	0	430	280	745
JUNE	35	0	0	0	430	280	745
JULY	35	0	0	0	430	280	745
AUGUST	35	0	0	0	430	280	745
SEPTEMBER	35	0	0	0	430	280	745
OCTOBER	180	0	0	0	280	280	740
NOVEMBER	180	0	0	0	255	280	715
DECEMBER	180	0	0	0	255	280	715
JANUARY 2011	175	0	0	0	255	280	710
FEBRUARY	175	0	0	0	255	280	710
MARCH	175	0	0	0	255	280	710
APRIL	175	0	0	0	280	280	735
MAY	30	0	0	0	430	280	740
JUNE	30	0	0	0	430	280	740
JULY	30	0	0	0	430	280	740
AUGUST	30	0	0	0	430	280	740
SEPTEMBER	30	0	0	0	430	280	740
OCTOBER	175	0	0	0	280	280	735
NOVEMBER	175	0	0	0	255	280	710
DECEMBER	175	0	0	0	255	280	710
JANUARY 2012	170	0	0	0	255	280	705
FEBRUARY	170	0	0	0	255	280	705
MARCH	170	0	0	0	255	280	705
APRIL	170	0	0	0	280	280	730
MAY	25	0	0	0	430	280	735
JUNE	25	0	0	0	430	280	735
JULY	25	0	0	0	430	280	735
AUGUST	25	0	0	0	430	280	735
SEPTEMBER	25	0	0	0	430	280	735
OCTOBER	170	0	0	0	280	280	730
NOVEMBER	170	0	0	0	255	280	705
DECEMBER	170	0	0	0	255	280	705
2010	120	5	5	17	327	263	732
2011	115	0	0	0	332	280	727
2012	110	0	0	0	332	280	722

MONTH	NON-FIRM TRANSPORT SERVICE	FIRM TRANSPORTATION SERVICE: PHASE II FIRM GAS SUPPLY TAKE OR PAY MINIMUM	FIRM TRANSPORTATION SERVICE: PHASE II FIRM GAS SUPPLY (SEE NOTE 1) MAXIMUM	FIRM TRANSPORTATION SERVICE: PHASE III FIRM GAS SUPPLY (TAKE OR PAY) (SEE NOTE 2) FIXED	PHASE II NON-FIRM GAS SUPPLY (SEE NOTE 1) MAXIMUM	PHASE III NON-FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	TOTAL (MAXIMUM) NATURAL GAS AVAILABILITY
JANUARY 2013	165	0	0	0	255	280	700
FEBRUARY	165	0	0	0	255	280	700
MARCH	165	0	0	0	255	280	700
APRIL	165	0	0	0	280	280	725
MAY	20	0	0	0	430	280	730
JUNE	20	0	0	0	430	280	730
JULY	20	0	0	0	430	280	730
AUGUST	20	0	0	0	430	280	730
SEPTEMBER	20	0	0	0	430	280	730
OCTOBER	165	0	0	0	280	280	725
NOVEMBER	165	0	0	0	255	280	700
DECEMBER	165	0	0	0	255	280	700
JANUARY 2014	160	0	0	0	255	280	695
FEBRUARY	160	0	0	0	255	280	695
MARCH	160	0	0	0	255	280	695
APRIL	160	0	0	0	280	280	720
MAY	15	0	0	0	430	280	725
JUNE	15	0	0	0	430	280	725
JULY	15	0	0	0	430	280	725
AUGUST	15	0	0	0	430	280	725
SEPTEMBER	15	0	0	0	430	280	725
OCTOBER	160	0	0	0	280	280	720
NOVEMBER	160	0	0	0	255	280	695
DECEMBER	160	0	0	0	255	280	695
JANUARY 2015	155	0	0	0	255	280	690
FEBRUARY	155	0	0	0	255	280	690
MARCH	155	0	0	0	255	280	690
APRIL	155	0	0	0	280	280	715
MAY	10	0	0	0	430	280	720
JUNE	10	0	0	0	430	280	720
JULY	10	0	0	0	430	280	720
AUGUST	10	0	0	0	430	280	720
SEPTEMBER	10	0	0	0	430	280	720
OCTOBER	155	0	0	0	280	280	715
NOVEMBER	155	0	0	0	255	280	690
DECEMBER	155	0	0	0	255	280	690
2013	105	0	0	0	332	280	717
2014	100	0	0	0	332	280	712
2015	95	0	0	0	332	280	707

NOTE 1: FOR PURPOSES OF ANALYSIS, FROM MARCH, 1995 THROUGH JULY, 2005, ASSUME THAT UP TO 332 MILLION CUBIC FEET PER DAY OF THE PHASE II TRANSPORTATION CAPACITY WILL BE AVAILABLE TO FPL. FOR THESE VOLUMES, ASSUME THE TRANSPORTATION DEMAND CHARGE IS A SUNK COST. FROM AUGUST, 2005 FORWARD, ASSUME THAT THESE PHASE II VOLUMES ARE STILL AVAILABLE, HOWEVER, 100% OF THE DELIVERED NATURAL GAS PRICE IS VARIABLE. (I.e. THE TRANSPORTATION DEMAND CHARGE IS NOT TAKE OR PAY) UNTIL A DECISION IS MADE ON THE VOLUME OF PHASE II TRANSPORTATION SERVICE FPL WILL COMMIT TO AFTER JULY, 2005. THEREAFTER, THE NEW FIRM TRANSPORTATION DEMAND CHARGE WILL BECOME A SUNK COST.

NOTE 2: FOR PURPOSES OF ANALYSIS, FROM MARCH, 1995 THROUGH FEBRUARY, 2010, ASSUME THAT UP TO 200 MILLION CUBIC FEET PER DAY OF THE PHASE III TRANSPORTATION CAPACITY WILL BE AVAILABLE TO FPL. FOR THESE VOLUMES, ASSUME THE TRANSPORTATION DEMAND CHARGE IS A SUNK COST. FROM MARCH, 2010 FORWARD, ASSUME THAT THESE PHASE III VOLUMES ARE STILL AVAILABLE, HOWEVER, 100% OF THE DELIVERED NATURAL GAS PRICE IS VARIABLE. (I.e. THE TRANSPORTATION DEMAND CHARGE IS NOT TAKE OR PAY) UNTIL A DECISION IS MADE ON THE VOLUME OF PHASE III FIRM TRANSPORTATION SERVICE AND FIRM NATURAL GAS SUPPLY FPL WILL COMMIT TO AFTER FEBRUARY, 2010. THEREAFTER, THE NEW FIRM TRANSPORTATION DEMAND CHARGE WILL BECOME A SUNK COST.

ENERGY MARKETING AND TRADING DIVISION
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FPL 1998-2027 LONG-TERM BASE CASE FOSSIL FUEL PRICE AND NATURAL GAS AVAILABILITY FORECAST
NATURAL GAS AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY (SEE NOTE 3)

MONTH	NON-FIRM TRANSPORT SERVICE	***FIRM TRANSPORTATION SERVICE*** PHASE II FIRM GAS SUPPLY TAKE OR PAY MINIMUM	GAS SUPPLY (SEE NOTE 1) MAXIMUM	PHASE III FIRM GAS SUPPLY (TAKE OR PAY) (SEE NOTE 2) FIXED	PHASE II NON-FIRM GAS SUPPLY (SEE NOTE 1) MAXIMUM	PHASE III NON-FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	TOTAL (MAXIMUM) NATURAL GAS AVAILABILITY
JANUARY 2016	150	0	0	0	255	280	685
FEBRUARY	150	0	0	0	255	280	685
MARCH	150	0	0	0	255	280	685
APRIL	150	0	0	0	280	280	710
MAY	5	0	0	0	430	280	715
JUNE	5	0	0	0	430	280	715
JULY	5	0	0	0	430	280	715
AUGUST	5	0	0	0	430	280	715
SEPTEMBER	5	0	0	0	430	280	715
OCTOBER	150	0	0	0	280	280	710
NOVEMBER	150	0	0	0	255	280	685
DECEMBER	150	0	0	0	255	280	685
JANUARY 2017	145	0	0	0	255	280	680
FEBRUARY	145	0	0	0	255	280	680
MARCH	145	0	0	0	255	280	680
APRIL	145	0	0	0	280	280	705
MAY	0	0	0	0	430	280	710
JUNE	0	0	0	0	430	280	710
JULY	0	0	0	0	430	280	710
AUGUST	0	0	0	0	430	280	710
SEPTEMBER	0	0	0	0	430	280	710
OCTOBER	145	0	0	0	280	280	705
NOVEMBER	145	0	0	0	255	280	680
DECEMBER	145	0	0	0	255	280	680
JANUARY 2018	140	0	0	0	255	280	675
FEBRUARY	140	0	0	0	255	280	675
MARCH	140	0	0	0	255	280	675
APRIL	140	0	0	0	280	280	700
MAY	0	0	0	0	430	280	710
JUNE	0	0	0	0	430	280	710
JULY	0	0	0	0	430	280	710
AUGUST	0	0	0	0	430	280	710
SEPTEMBER	0	0	0	0	430	280	710
OCTOBER	140	0	0	0	280	280	700
NOVEMBER	140	0	0	0	255	280	675
DECEMBER	140	0	0	0	255	280	675
2016	90	0	0	0	332	280	702
2017	85	0	0	0	332	280	697
2018	82	0	0	0	332	280	694

MONTH	NON-FIRM TRANSPORT SERVICE	***FIRM TRANSPORTATION SERVICE*** PHASE II FIRM GAS SUPPLY TAKE OR PAY MINIMUM	GAS SUPPLY (SEE NOTE 1) MAXIMUM	PHASE III FIRM GAS SUPPLY (TAKE OR PAY) (SEE NOTE 2) FIXED	PHASE II NON-FIRM GAS SUPPLY (SEE NOTE 1) MAXIMUM	PHASE III NON-FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	TOTAL (MAXIMUM) NATURAL GAS AVAILABILITY
JANUARY 2019	135	0	0	0	255	280	670
FEBRUARY	135	0	0	0	255	280	670
MARCH	135	0	0	0	255	280	670
APRIL	135	0	0	0	280	280	695
MAY	0	0	0	0	430	280	710
JUNE	0	0	0	0	430	280	710
JULY	0	0	0	0	430	280	710
AUGUST	0	0	0	0	430	280	710
SEPTEMBER	0	0	0	0	430	280	710
OCTOBER	135	0	0	0	280	280	695
NOVEMBER	135	0	0	0	255	280	670
DECEMBER	135	0	0	0	255	280	670
JANUARY 2020	130	0	0	0	255	280	665
FEBRUARY	130	0	0	0	255	280	665
MARCH	130	0	0	0	255	280	665
APRIL	130	0	0	0	280	280	690
MAY	0	0	0	0	430	280	710
JUNE	0	0	0	0	430	280	710
JULY	0	0	0	0	430	280	710
AUGUST	0	0	0	0	430	280	710
SEPTEMBER	0	0	0	0	430	280	710
OCTOBER	130	0	0	0	280	280	690
NOVEMBER	130	0	0	0	255	280	665
DECEMBER	130	0	0	0	255	280	665
JANUARY 2021	125	0	0	0	255	280	660
FEBRUARY	125	0	0	0	255	280	660
MARCH	125	0	0	0	255	280	660
APRIL	125	0	0	0	280	280	685
MAY	0	0	0	0	430	280	710
JUNE	0	0	0	0	430	280	710
JULY	0	0	0	0	430	280	710
AUGUST	0	0	0	0	430	280	710
SEPTEMBER	0	0	0	0	430	280	710
OCTOBER	125	0	0	0	280	280	685
NOVEMBER	125	0	0	0	255	280	660
DECEMBER	125	0	0	0	255	280	660
2019	79	0	0	0	332	280	691
2020	76	0	0	0	332	280	688
2021	73	0	0	0	332	280	685

NOTE 1: FOR PURPOSES OF ANALYSIS, FROM MARCH, 1995 THROUGH JULY, 2005, ASSUME THAT UP TO 332 MILLION CUBIC FEET PER DAY OF THE PHASE II TRANSPORTATION CAPACITY WILL BE AVAILABLE TO FPL. FOR THESE VOLUMES, ASSUME THE TRANSPORTATION DEMAND CHARGE IS A SUNK COST. FROM AUGUST, 2005 FORWARD, ASSUME THAT THESE PHASE II VOLUMES ARE STILL AVAILABLE, HOWEVER, 100% OF THE DELIVERED NATURAL GAS PRICE IS VARIABLE. (I.e. THE TRANSPORTATION DEMAND CHARGE IS NOT TAKE OR PAY) UNTIL A DECISION IS MADE ON THE VOLUME OF PHASE II TRANSPORTATION SERVICE FPL WILL COMMIT TO AFTER JULY, 2005. THEREAFTER, THE NEW FIRM TRANSPORTATION DEMAND CHARGE WILL BECOME A SUNK COST.

NOTE 2: FOR PURPOSES OF ANALYSIS, FROM MARCH, 1995 THROUGH FEBRUARY, 2010, ASSUME THAT UP TO 200 MILLION CUBIC FEET PER DAY OF THE PHASE III TRANSPORTATION CAPACITY WILL BE AVAILABLE TO FPL. FOR THESE VOLUMES, ASSUME THE TRANSPORTATION DEMAND CHARGE IS A SUNK COST. FROM MARCH, 2010 FORWARD, ASSUME THAT THESE PHASE III VOLUMES ARE STILL AVAILABLE, HOWEVER, 100% OF THE DELIVERED NATURAL GAS PRICE IS VARIABLE. (I.e. THE TRANSPORTATION DEMAND CHARGE IS NOT TAKE OR PAY) UNTIL A DECISION IS MADE ON THE VOLUME OF PHASE III FIRM TRANSPORTATION SERVICE AND FIRM NATURAL GAS SUPPLY FPL WILL COMMIT TO AFTER FEBRUARY, 2010. THEREAFTER, THE NEW FIRM TRANSPORTATION DEMAND CHARGE WILL BECOME A SUNK COST.

NOTE 3: FOR 2022 THROUGH 2027, ASSUME THE SAME MONTHLY AVAILABILITY AS IN 2021.

ENERGY MARKETING AND TRADING DIVISION
APRIL, 1998 - EUGENE UNGAR

Florida Power and Light Co.
Docket No. 971004-EG
Testimony of Steve Sim
Exhibit No. ___
Document No. 3

FPL 1998-2027 LONG-TERM BASE CASE FOSSIL FUEL PRICE AND NATURAL GAS AVAILABILITY FORECAST

DELIVERED NOMINAL DOLLAR NATURAL GAS PRICES

APRIL, 1998

YEAR	THREE DAY AVERAGE NYMEX SETTLEMENT $/MMBTU	AVERAGE OF ZONES 1, 2 & 3 FGT BASIS $/MMBTU	AVERAGE OF ZONES 1, 2 & 3 DELIVERED INTO FGT $/MMBTU
1997			
1998	$2.45	($0.04)	$2.41
1999	$2.50	($0.04)	$2.47
2000	$2.55	($0.03)	$2.52
2001	$2.65	($0.03)	$2.63
2002	$2.80	($0.02)	$2.78
2003	$3.00	($0.02)	$2.99
2004	$3.15	($0.01)	$3.14
2005	$3.25	($0.01)	$3.25
2006	$3.30	$0.00	$3.30
2007	$3.35	$0.00	$3.35
2008	$3.40	$0.00	$3.40
2009	$3.45	$0.00	$3.45
2010	$3.50	$0.00	$3.50
2011	$3.55	$0.00	$3.55
2012	$3.65	$0.00	$3.65
2013	$3.81	$0.00	$3.81
2014	$3.96	$0.00	$3.96
2015	$4.04	$0.00	$4.04
2016	$4.14	$0.00	$4.14
2017	$4.25	$0.00	$4.25
2018	$4.36	$0.00	$4.36
2019	$4.47	$0.00	$4.47
2020	$4.59	$0.00	$4.59
2021	$4.70	$0.00	$4.70
2022	$4.83	$0.00	$4.83
2023	$4.95	$0.00	$4.95
2024	$5.08	$0.00	$5.08
2025	$5.21	$0.00	$5.21
2026	$5.35	$0.00	$5.35
2027	$5.48	$0.00	$5.48

YEAR	A=B+E SYSTEM WEIGHTED AVERAGE TOTAL (NON-FIRM & FIRM) NATURAL GAS PRICE $/MMBTU	MM$	B VARIABLE (DISPATCH) COST FOR GAS MOVING UNDER NON-FIRM TRANSPORATION $/MMBTU	MM$	C VARIABLE (DISPATCH) COST FOR GAS MOVING UNDER FIRM TRANSPORATION $/MMBTU	MM$	D DEMAND (SUNK) COST FOR GAS MOVING UNDER FIRM TRANSPORATION $/MMBTU	MM$
1997								
1998	$3.10	$559.88	$2.84	$96.99	$2.54	$372.07	$0.62	$90.81
1999	$3.12	$800.63	$2.91	$180.76	$2.60	$504.75	$0.59	$115.11
2000	$3.16	$801.83	$2.97	$174.49	$2.66	$517.15	$0.57	$110.19
2001	$3.27	$815.44	$3.09	$169.61	$2.76	$536.81	$0.56	$109.02
2002	$3.46	$974.99	$3.26	$190.78	$2.92	$652.44	$0.59	$131.76
2003	$3.67	$1,028.17	$3.48	$196.34	$3.13	$699.46	$0.59	$132.36
2004	$3.83	$1,069.51	$3.65	$200.39	$3.29	$737.04	$0.59	$132.09
2005	$3.95	$1,091.01	$3.77	$199.47	$3.49	$778.95	$0.50	$112.59
2006	$4.01	$1,100.55	$3.84	$196.02	$3.66	$818.73	$0.38	$85.79
2007	$4.06	$1,108.43	$3.90	$192.08	$3.72	$830.53	$0.38	$85.82
2008	$4.12	$1,117.76	$3.96	$188.45	$3.76	$843.20	$0.38	$86.11
2009	$4.17	$1,121.48	$4.02	$183.58	$3.81	$852.24	$0.38	$85.66
2010	$4.21	$1,125.96	$4.09	$179.02	$4.16	$928.65	$0.08	$18.29
2011	$4.27	$1,132.72	$4.15	$174.23	$4.29	$958.49	$0.00	$0.00
2012	$4.37	$1,155.93	$4.27	$171.77	$4.39	$984.16	$0.00	$0.00
2013	$4.54	$1,187.44	$4.44	$170.21	$4.55	$1,017.23	$0.00	$0.00
2014	$4.70	$1,220.66	$4.61	$168.40	$4.71	$1,052.26	$0.00	$0.00
2015	$4.78	$1,233.01	$4.71	$163.19	$4.79	$1,069.82	$0.00	$0.00
2016	$4.89	$1,256.38	$4.83	$159.03	$4.90	$1,097.36	$0.00	$0.00
2017	$5.01	$1,273.61	$4.95	$153.65	$5.01	$1,119.95	$0.00	$0.00
2018	$5.12	$1,294.03	$5.08	$148.36	$5.13	$1,145.67	$0.00	$0.00
2019	$5.24	$1,314.73	$5.21	$142.69	$5.25	$1,172.04	$0.00	$0.00
2020	$5.36	$1,336.87	$5.35	$137.01	$5.36	$1,199.86	$0.00	$0.00
2021	$5.48	$1,353.51	$5.49	$130.17	$5.48	$1,223.35	$0.00	$0.00
2022	$5.60	$1,374.56	$5.63	$123.28	$5.60	$1,251.28	$0.00	$0.00
2023	$5.73	$1,396.20	$5.78	$115.94	$5.73	$1,280.26	$0.00	$0.00
2024	$5.87	$1,421.79	$5.93	$108.44	$5.86	$1,313.35	$0.00	$0.00
2025	$6.00	$1,450.90	$6.08	$110.96	$6.00	$1,339.94	$0.00	$0.00
2026	$6.14	$1,484.57	$6.24	$113.85	$6.14	$1,370.73	$0.00	$0.00
2027	$6.29	$1,519.41	$6.40	$116.81	$6.28	$1,402.59	$0.00	$0.00

YEAR	E=C+D TOTAL COST FOR GAS MOVING UNDER FIRM TRANSPORATION $/MMBTU	MM$	AVERAGE VARIABLE (DISPATCH) COST FOR GAS MOVING UNDER FIRM & NON-FIRM TRANSPORATION $/MMBTU	MM$	COST OF NATURAL GAS MOVING UNDER FIRM PHASE IV TRANSPORTATION: DELIVERED PRICE $/MMBTU	VARIABLE DISPATCH PRICE $/MMBTU	DEMAND (SUNK) COST $/MMBTU
1997							
1998	$3.16	$462.88	$2.60	$469.06	$3.30	$2.53	$0.77
1999	$3.19	$619.86	$2.67	$685.51	$3.35	$2.58	$0.77
2000	$3.22	$627.34	$2.73	$691.64	$3.41	$2.64	$0.78
2001	$3.33	$645.83	$2.84	$706.42	$3.52	$2.74	$0.78
2002	$3.51	$784.21	$2.99	$843.23	$3.68	$2.90	$0.79
2003	$3.72	$831.82	$3.20	$895.80	$3.90	$3.10	$0.79
2004	$3.88	$869.13	$3.36	$937.43	$4.06	$3.26	$0.80
2005	$3.99	$891.54	$3.54	$978.43	$4.18	$3.37	$0.80
2006	$4.05	$904.53	$3.70	$1,014.76	$4.24	$3.43	$0.81
2007	$4.10	$916.35	$3.75	$1,022.61	$4.30	$3.49	$0.82
2008	$4.15	$929.31	$3.80	$1,031.65	$4.34	$3.52	$0.82
2009	$4.20	$937.90	$3.85	$1,035.82	$4.39	$3.56	$0.83
2010	$4.24	$946.94	$4.15	$1,107.67	$4.44	$4.30	$0.83
2011	$4.29	$958.49	$4.27	$1,132.72	$4.49	$4.49	$0.83
2012	$4.39	$984.16	$4.37	$1,155.93	$4.59	$4.59	$0.83
2013	$4.55	$1,017.23	$4.54	$1,187.44	$4.75	$4.75	$0.83
2014	$4.71	$1,052.26	$4.70	$1,220.66	$4.90	$4.90	$0.83
2015	$4.79	$1,069.82	$4.78	$1,233.01	$4.97	$4.97	$0.83
2016	$4.90	$1,097.36	$4.89	$1,256.38	$5.08	$5.08	$0.83
2017	$5.01	$1,119.95	$5.01	$1,273.61	$5.20	$5.20	$0.83
2018	$5.13	$1,145.67	$5.12	$1,294.03	$5.32	$5.32	$0.83
2019	$5.25	$1,172.04	$5.24	$1,314.73	$5.43	$5.43	$0.83
2020	$5.36	$1,199.86	$5.36	$1,336.87	$5.53	$5.53	$0.83
2021	$5.48	$1,223.35	$5.48	$1,353.51	$5.64	$5.64	$0.83
2022	$5.60	$1,251.28	$5.60	$1,374.56	$5.77	$5.77	$0.83
2023	$5.73	$1,280.26	$5.73	$1,396.20	$5.89	$5.89	$0.83
2024	$5.88	$1,313.35	$5.87	$1,421.79	$6.02	$6.02	$0.83
2025	$6.00	$1,339.94	$6.00	$1,450.90	$6.15	$6.15	$0.83
2026	$6.14	$1,370.73	$6.14	$1,484.57	$6.28	$6.28	$0.83
2027	$6.28	$1,402.59	$6.29	$1,519.41	$6.42	$6.42	$0.83

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FPL 1998-2027 LONG-TERM BASE CASE FOSSIL FUEL PRICE AND NATURAL GAS AVAILABILITY FORECAST

DELIVERED NOMINAL DOLLAR RESIDUAL (NO. 6) FUEL OIL PRICES BY SULFUR GRADE

APRIL, 1998

YEAR	****0.7% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		****1.0% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		****1.6% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		****2.0% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		****2.6% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		****3.0% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL	
	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU
1997												
1998	$14.48	$2.26	$13.89	$2.17	$13.33	$2.08	$12.83	$2.00	$12.33	$1.93	$11.83	$1.85
1999	$16.64	$2.60	$15.79	$2.47	$15.24	$2.38	$14.67	$2.29	$15.31	$2.39	$13.59	$2.12
2000	$18.50	$2.89	$17.41	$2.72	$16.86	$2.63	$16.21	$2.53	$16.86	$2.63	$15.05	$2.35
2001	$20.26	$3.17	$18.95	$2.96	$18.37	$2.87	$17.66	$2.76	$18.31	$2.86	$16.42	$2.57
2002	$21.63	$3.38	$20.08	$3.14	$19.48	$3.04	$18.68	$2.92	$19.34	$3.02	$17.37	$2.71
2003	$22.81	$3.56	$21.05	$3.29	$20.42	$3.19	$19.55	$3.06	$20.23	$3.16	$18.18	$2.84
2004	$24.37	$3.81	$22.47	$3.51	$21.62	$3.38	$20.77	$3.24	$21.25	$3.32	$19.06	$2.98
2005	$26.00	$4.06	$23.85	$3.73	$22.90	$3.58	$21.95	$3.43	$22.37	$3.49	$20.04	$3.13
2006	$27.72	$4.33	$25.32	$3.96	$24.27	$3.79	$23.22	$3.63	$23.57	$3.68	$21.11	$3.30
2007	$29.54	$4.62	$26.89	$4.20	$25.73	$4.02	$24.58	$3.84	$24.87	$3.89	$22.28	$3.48
2008	$31.46	$4.92	$28.55	$4.46	$27.30	$4.27	$26.05	$4.07	$26.27	$4.10	$23.54	$3.68
2009	$33.20	$5.19	$30.04	$4.69	$28.68	$4.48	$27.33	$4.27	$27.49	$4.30	$24.62	$3.85
2010	$34.84	$5.44	$31.43	$4.91	$29.98	$4.68	$28.52	$4.46	$28.62	$4.47	$25.61	$4.00
2011	$36.49	$5.70	$32.83	$5.13	$31.27	$4.89	$29.72	$4.64	$29.76	$4.65	$26.61	$4.16
2012	$38.05	$5.95	$34.14	$5.33	$32.48	$5.08	$30.82	$4.82	$30.81	$4.81	$27.51	$4.30
2013	$39.42	$6.16	$35.25	$5.51	$33.50	$5.23	$31.74	$4.96	$31.67	$4.95	$28.23	$4.41
2014	$41.05	$6.41	$36.63	$5.72	$34.77	$5.43	$32.91	$5.14	$32.78	$5.12	$29.20	$4.56
2015	$42.26	$6.60	$37.59	$5.87	$35.63	$5.57	$33.67	$5.26	$33.49	$5.23	$29.76	$4.65
2016	$43.50	$6.80	$38.58	$6.03	$36.52	$5.71	$34.46	$5.38	$34.23	$5.35	$30.35	$4.74
2017	$44.77	$7.00	$39.59	$6.19	$37.43	$5.85	$35.27	$5.51	$34.99	$5.47	$30.96	$4.84
2018	$46.06	$7.20	$40.63	$6.35	$38.37	$6.00	$36.11	$5.64	$35.77	$5.59	$31.59	$4.94
2019	$47.38	$7.40	$41.69	$6.51	$39.33	$6.15	$36.97	$5.78	$36.59	$5.72	$32.25	$5.04
2020	$48.72	$7.61	$42.78	$6.68	$40.32	$6.30	$37.86	$5.92	$37.43	$5.85	$32.94	$5.15
2021	$50.09	$7.83	$43.90	$6.86	$41.34	$6.46	$38.78	$6.06	$38.30	$5.98	$33.65	$5.26
2022	$51.48	$8.04	$45.04	$7.04	$42.38	$6.62	$39.72	$6.21	$39.20	$6.12	$34.39	$5.37
2023	$52.90	$8.27	$46.21	$7.22	$43.45	$6.79	$40.69	$6.36	$40.12	$6.27	$35.16	$5.49
2024	$54.36	$8.49	$47.41	$7.41	$44.55	$6.96	$41.69	$6.51	$41.08	$6.42	$35.96	$5.62
2025	$55.84	$8.72	$48.64	$7.60	$45.68	$7.14	$42.71	$6.67	$42.07	$6.57	$36.79	$5.75
2026	$57.35	$8.96	$49.90	$7.80	$46.84	$7.32	$43.77	$6.84	$43.09	$6.73	$37.64	$5.88
2027	$58.89	$9.20	$51.19	$8.00	$48.03	$7.50	$44.86	$7.01	$44.14	$6.90	$38.53	$6.02

NOTE: RESIDUAL FUEL OIL PRICES ARE DELIVERED PRICES TO ALL FPL PLANT SITES.

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Projected FPL Resource Need (MW): 2001 - 2009

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*Projected FPL Resource Needs (MW): 2001 - 2009**

Year	Incremental Annual Need MW	Cumulative Need MW
2001	0	0
2002	0	0
2003	0	0
2004	0	0
2005	350	350
2006	303	653
2007	423	1076
2008	395	1471
2009	434	1905

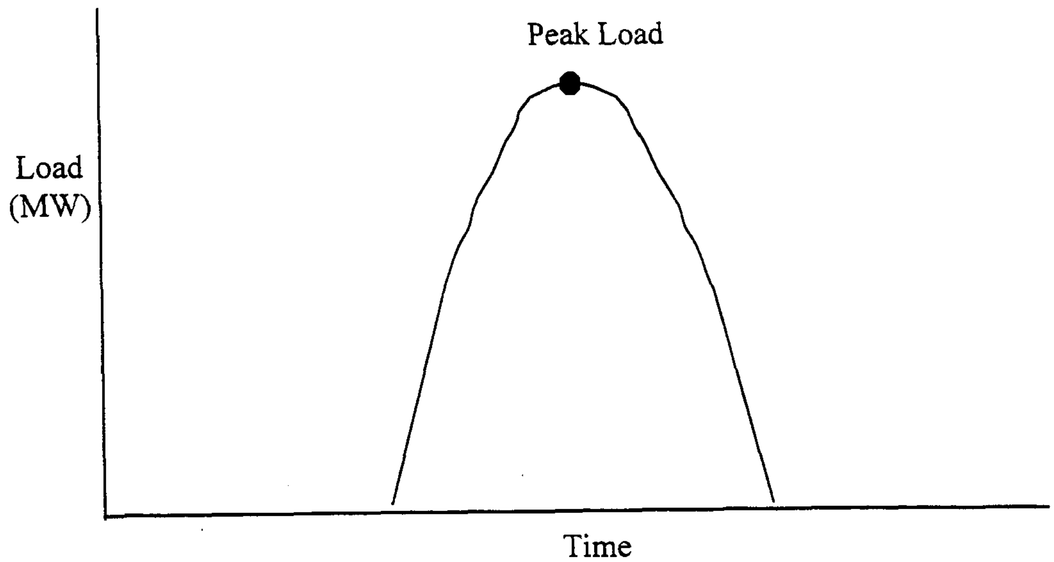
*** Assumptions include:**

-Resource needs will be met solely by capacity additions.
-Repowered Ft. Myers and Sanford units come in-service by January 2002,and January 2003, respectively, with combustion turbine components of the repowering work coming in-service in the year prior to the respective in-service date.
-No additional DSM is added after the year 2000.

Document No. 5

Hypothetical Utility Peak Day Load Shape

Hypothetical Utility Peak Day Load Shape



Document No. 6

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

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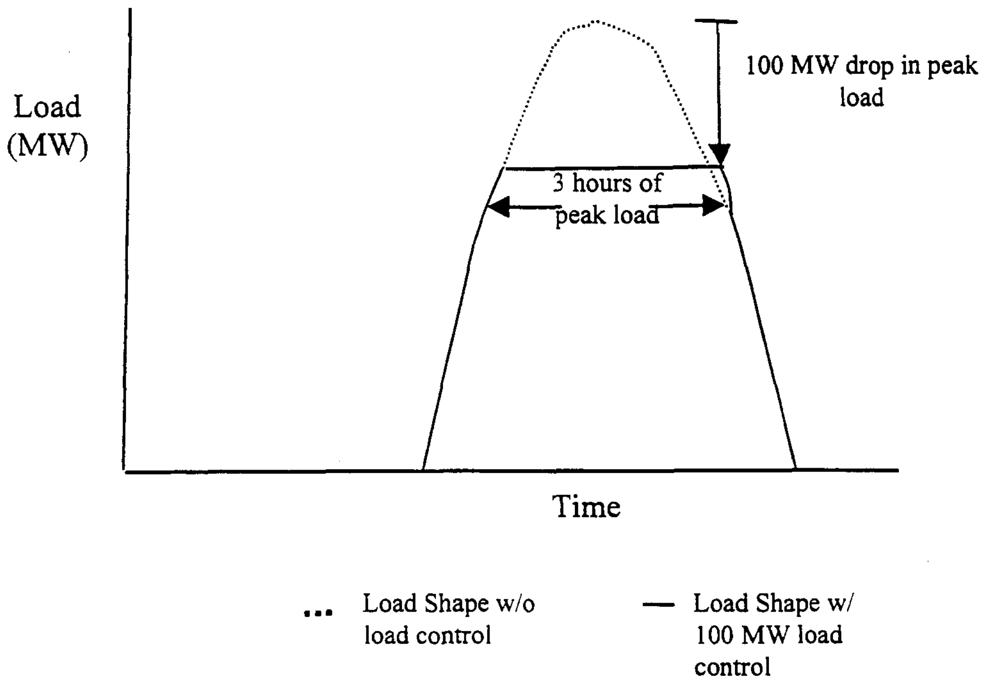
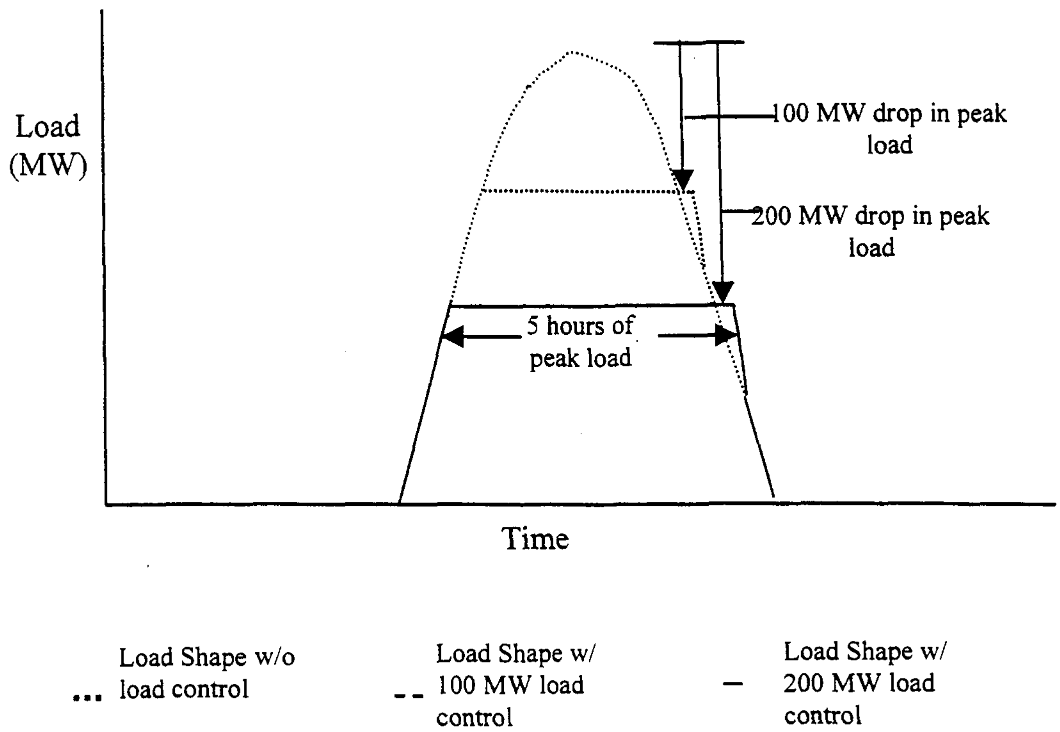
Representative Effect of Implementing 100 MW of Load Control on the Hypothetical Utility Peak Day Load Shape



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



Document No. 7

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

FPL 1998-2027 LONG-TERM BASE CASE FOSSIL FUEL PRICE AND NATURAL GAS AVAILABILITY FORECAST

DELIVERED NOMINAL DOLLAR COAL TO SJRPP, ORIMULSION TO MANATEE & MARTIN

APRIL, 1998

	DELIVERED ST. JOHNS RIVER POWER PARK FUEL PRICES (INCLUDES VARIABLE O & M COSTS)										DISPATCH PRICE OF FUEL AT SJRPP (80% SPOT COAL; 20% PETROLEUM COKE		DELIVERED NOMINAL ORIMULSION PRICES — EXCESS PRICE INCLUDES VARIABLE O & M EXPENSES			
	CONTRACT COAL PRICE NOMINAL		SPOT COAL PRICE NOMINAL		WEIGHTED AVERAGE COAL PRICE NOMINAL		PETROLEUM COKE NOMINAL		WEIGHTED AVERAGE FUEL PRICE NOMINAL				MANATEE		MARTIN	
YEAR	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	BASE PRICE $/MMBTU	EXCESS PRICE $/MMBTU	BASE PRICE $/MMBTU	EXCESS PRICE $/MMBTU
1998	$39.77	$1.62	$41.38	$1.64	$39.94	$1.62	$15.63	$0.56	$35.36	$1.42	$36.23	$1.42				
1999	$40.44	$1.64	$41.84	$1.66	$40.69	$1.65	$15.88	$0.57	$36.23	$1.45	$36.65	$1.44				
2000	$41.26	$1.67	$42.86	$1.70	$41.52	$1.68	$16.19	$0.58	$36.96	$1.48	$37.37	$1.47	$1.76	$1.56		
2001	$38.72	$1.62	$43.48	$1.73	$40.67	$1.66	$16.50	$0.59	$36.32	$1.47	$38.08	$1.50	$1.70	$1.59	$1.84	$1.77
2002	$39.41	$1.65	$44.31	$1.76	$41.41	$1.69	$16.81	$0.60	$36.99	$1.50	$38.81	$1.53	$1.73	$1.62	$1.88	$1.81
2003	$39.12	$1.66	$45.21	$1.80	$42.47	$1.74	$17.16	$0.61	$38.24	$1.54	$39.60	$1.56	$1.75	$1.65	$1.89	$1.85
2004	$39.16	$1.66	$46.16	$1.64	$42.66	$1.75	$17.55	$0.63	$37.64	$1.52	$40.44	$1.59	$1.75	$1.69	$1.90	$1.89
2005	$39.20	$1.66	$47.08	$1.87	$42.75	$1.76	$17.92	$0.64	$37.78	$1.53	$41.25	$1.63	$1.76	$1.73	$1.91	$1.92
2006	$37.92	$1.61	$47.97	$1.91	$41.94	$1.73	$18.29	$0.65	$37.21	$1.51	$42.03	$1.66	$1.70	$1.71	$1.86	$1.91
2007	$38.85	$1.65	$48.86	$1.94	$42.36	$1.75	$18.80	$0.67	$37.64	$1.54	$42.85	$1.69	$1.74	$1.76	$1.90	$1.95
2008	$42.64	$1.81	$49.79	$1.98	$44.79	$1.86	$19.35	$0.69	$39.70	$1.63	$43.70	$1.72	$1.90	$1.84	$2.07	$2.04
2009	$43.66	$1.85	$50.75	$2.02	$45.79	$1.90	$19.89	$0.71	$40.61	$1.66	$44.57	$1.76	$1.95	$1.87	$2.12	$2.08
2010	$44.71	$1.90	$51.74	$2.06	$46.82	$1.95	$20.43	$0.73	$41.54	$1.70	$45.47	$1.79	$1.99	$1.91	$2.17	$2.12
2011	$45.82	$1.94	$52.73	$2.10	$47.89	$1.99	$20.98	$0.75	$42.51	$1.74	$46.38	$1.83	$2.04	$1.95	$2.22	$2.16
2012	$46.96	$1.99	$53.78	$2.14	$49.00	$2.04	$21.56	$0.77	$43.51	$1.78	$47.33	$1.87	$2.09	$1.99	$2.28	$2.20
2013	$48.51	$2.06	$54.85	$2.18	$50.41	$2.10	$22.15	$0.79	$44.76	$1.83	$48.31	$1.90	$2.16	$2.03	$2.35	$2.25
2014	$49.71	$2.11	$55.95	$2.23	$51.58	$2.14	$22.77	$0.81	$45.82	$1.88	$49.31	$1.94	$2.21	$2.08	$2.41	$2.29
2015	$51.01	$2.16	$57.08	$2.27	$52.83	$2.20	$23.41	$0.84	$46.95	$1.92	$50.35	$1.98	$2.27	$2.12	$2.47	$2.34
2016	$52.34	$2.22	$58.24	$2.32	$54.11	$2.25	$24.08	$0.86	$48.10	$1.97	$51.41	$2.03	$2.33	$2.17	$2.53	$2.39
2017	$53.59	$2.27	$59.41	$2.36	$55.33	$2.30	$24.78	$0.88	$49.22	$2.02	$52.48	$2.07	$2.38	$2.21	$2.59	$2.44
2018	$55.29	$2.35	$60.62	$2.41	$56.89	$2.37	$25.45	$0.91	$50.60	$2.07	$53.58	$2.11	$2.45	$2.26	$2.67	$2.49
2019	$56.56	$2.40	$61.85	$2.46	$58.15	$2.42	$26.11	$0.93	$51.74	$2.12	$54.70	$2.15	$2.51	$2.31	$2.73	$2.54
2020	$57.87	$2.46	$63.11	$2.51	$59.44	$2.47	$26.78	$0.96	$52.91	$2.17	$55.85	$2.20	$2.51	$2.31	$2.79	$2.59
2021	$59.21	$2.51	$64.40	$2.56	$60.77	$2.53	$27.47	$0.98	$54.11	$2.22	$57.02	$2.25	$2.51	$2.31	$2.79	$2.59
2022	$60.58	$2.57	$65.72	$2.61	$62.12	$2.58	$28.17	$1.01	$55.33	$2.27	$58.21	$2.29	$2.51	$2.31	$2.79	$2.59
2023	$62.44	$2.65	$67.07	$2.67	$63.83	$2.65	$28.89	$1.03	$56.84	$2.33	$59.43	$2.34	$2.51	$2.31	$2.79	$2.59
2024	$63.88	$2.71	$68.44	$2.72	$65.25	$2.71	$29.63	$1.06	$58.12	$2.38	$60.68	$2.39	$2.51	$2.31	$2.79	$2.59
2025	$65.35	$2.77	$69.84	$2.78	$66.70	$2.77	$30.38	$1.09	$59.44	$2.44	$61.95	$2.44	$2.51	$2.31	$2.79	$2.59
2026	$66.83	$2.84	$71.27	$2.83	$68.16	$2.84	$31.16	$1.11	$60.76	$2.49	$63.25	$2.49	$2.51	$2.31	$2.79	$2.59
2027	$68.33	$2.90	$72.73	$2.89	$69.65	$2.90	$31.93	$1.14	$62.11	$2.55	$64.57	$2.54	$2.51	$2.31	$2.79	$2.59

ENERGY MARKETING AND TRADING DIVISION
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NOMINAL DOLLAR CRUDE OIL AND DELIVERED DISTILLATE (NO. 2) FUEL OIL PRICES

APRIL, 1998

	*******NOMINAL CRUDE OIL PRICES********				(SEE NOTE 1) *****0.5% SULFUR****** **DISTILLATE FUEL OIL** DELIVERED NOMINAL		(SEE NOTE 2) *****0.3% SULFUR****** **DISTILLATE FUEL OIL* DELIVERED NOMINAL	
	ARABIAN LIGHT		****WEST TEXAS***** ***INTERMEDIATE****					
YEAR	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU
1997								
1998	$14.00	$2.40	$16.25	$2.79	$20.04	$3.44	$20.59	$3.53
1999	$16.23	$2.78	$18.44	$3.16	$21.88	$3.75	$22.53	$3.86
2000	$18.21	$3.12	$20.54	$3.52	$23.99	$4.12	$24.68	$4.23
2001	$19.74	$3.39	$22.19	$3.81	$25.85	$4.43	$25.58	$4.39
2002	$20.78	$3.56	$23.36	$4.01	$27.55	$4.73	$28.33	$4.86
2003	$21.62	$3.71	$24.34	$4.17	$29.04	$4.98	$29.86	$5.12
2004	$22.91	$3.93	$25.77	$4.42	$31.40	$5.39	$32.25	$5.53
2005	$24.27	$4.16	$27.29	$4.68	$33.93	$5.82	$34.83	$5.97
2006	$25.71	$4.41	$28.89	$4.96	$36.67	$6.29	$37.61	$6.45
2007	$27.25	$4.67	$30.59	$5.25	$39.62	$6.80	$40.60	$6.96
2008	$28.88	$4.95	$32.39	$5.56	$42.80	$7.34	$43.82	$7.52
2009	$30.31	$5.20	$33.99	$5.83	$45.79	$7.85	$46.85	$8.04
2010	$31.62	$5.42	$35.49	$6.09	$48.71	$8.35	$49.81	$8.54
2011	$32.93	$5.65	$36.99	$6.34	$51.71	$8.87	$52.85	$9.06
2012	$34.13	$5.85	$38.39	$6.58	$54.62	$9.37	$55.80	$9.57
2013	$35.12	$6.02	$39.59	$6.79	$57.29	$9.83	$58.51	$10.04
2014	$36.37	$6.24	$41.05	$7.04	$60.43	$10.37	$61.69	$10.58
2015	$37.19	$6.38	$42.09	$7.22	$62.95	$10.80	$64.25	$11.02
2016	$38.02	$6.52	$43.16	$7.40	$65.54	$11.24	$66.89	$11.47
2017	$38.87	$6.67	$44.26	$7.59	$68.23	$11.70	$69.61	$11.94
2018	$39.73	$6.82	$45.38	$7.78	$70.99	$12.18	$72.42	$12.42
2019	$40.62	$6.97	$46.53	$7.98	$73.85	$12.67	$75.31	$12.92
2020	$41.52	$7.12	$47.70	$8.18	$76.79	$13.17	$78.30	$13.43
2021	$42.44	$7.28	$48.91	$8.39	$79.83	$13.69	$81.38	$13.96
2022	$43.38	$7.44	$50.15	$8.60	$82.96	$14.23	$84.55	$14.50
2023	$44.34	$7.61	$51.42	$8.82	$86.19	$14.78	$87.82	$15.06
2024	$45.32	$7.77	$52.72	$9.04	$89.52	$15.36	$91.19	$15.64
2025	$46.32	$7.95	$54.06	$9.27	$92.96	$15.94	$94.67	$16.24
2026	$47.34	$8.12	$55.42	$9.51	$96.50	$16.55	$98.25	$16.85
2027	$48.39	$8.30	$56.82	$9.75	$100.15	$17.18	$101.94	$17.48

NOTE 1: THE 0.5% *SULFUR DISTILLATE* FUEL OIL IS FOR THE GAS TURBINES AT FT. MYERS, LAUDERDALE AND PORT EVERGLADES, AND THE COMBINED CYCLE AT PUTNAM.

NOTE 2: THE 0.3% SULFUR DISTILLATE FUEL OIL IS FOR THE COMBINED CYCLE UNITS AT LAUDERDALE AND MARTIN.

ENERGY MARKETING AND TRADING DIVISION

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FPL 1998-2027 LONG-TERM BASE CASE FOSSIL FUEL PRICE AND NATURAL GAS AVAILABILITY FORECAST

DELIVERED NOMINAL DOLLAR COAL PRICES TO SCHERER UNIT 4 & THE MARTIN SITE,PETROLEUM COKE

APRIL, 1998

FORECAST ASSUMES THAT THE MARTIN COAL PLANT WILL STARTUP IN 2004

	PLANT SCHERER UNIT 4		MARTIN PLANT: LOW SULFUR COAL				MARTIN PLANT: HIGH SULFUR COAL				PETROLEUM COKE DELIVERED TO FLORIDA	
	WEIGHTED AVERAGE	SPOT PRICE	WEIGHTED AVERAGE NOMINAL		SPOT PRICE NOMINAL		WEIGHTED AVERAGE NOMINAL		SPOT PRICE NOMINAL		NOMINAL	
YEAR	$/MMBTU	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU
1998	$1.73	$1.53	$47.52	$1.95	$47.52	$1.95	$46.14	$2.01	$46.14	$2.01	$15.63	$0.56
1999	$1.72	$1.58	$48.58	$1.99	$48.58	$1.99	$47.16	$2.05	$47.16	$2.05	$15.88	$0.57
2000	$1.71	$1.60	$49.69	$2.04	$49.69	$2.04	$48.24	$2.10	$48.24	$2.10	$16.19	$0.58
2001	$1.75	$1.63	$50.91	$2.09	$50.91	$2.09	$49.43	$2.15	$49.43	$2.15	$16.50	$0.59
2002	$1.82	$1.67	$52.20	$2.14	$52.20	$2.14	$50.68	$2.20	$50.68	$2.20	$16.81	$0.60
2003	$1.89	$1.71	$53.54	$2.19	$53.54	$2.19	$51.99	$2.26	$51.99	$2.26	$17.16	$0.61
2004	$1.97	$1.76	$54.79	$2.25	$54.91	$2.25	$53.19	$2.31	$53.31	$2.32	$17.50	$0.63
2005	$2.04	$1.80	$56.03	$2.30	$56.27	$2.31	$54.40	$2.37	$54.64	$2.38	$17.86	$0.64
2006	$2.08	$1.84	$57.39	$2.35	$57.74	$2.37	$55.71	$2.42	$56.06	$2.44	$18.19	$0.65
2007	$2.13	$1.88	$58.82	$2.41	$59.30	$2.43	$57.10	$2.48	$57.58	$2.50	$18.53	$0.66
2008	$2.18	$1.92	$60.51	$2.48	$60.85	$2.49	$58.71	$2.55	$59.08	$2.57	$18.88	$0.67
2009	$1.96	$1.96	$61.91	$2.54	$62.39	$2.56	$60.07	$2.61	$60.57	$2.63	$19.24	$0.69
2010	$2.00	$2.00	$63.34	$2.60	$63.95	$2.62	$61.46	$2.67	$62.09	$2.70	$19.62	$0.70
2011	$2.04	$2.04	$64.86	$2.66	$65.61	$2.69	$62.93	$2.74	$63.70	$2.77	$20.00	$0.71
2012	$2.08	$2.08	$66.42	$2.72	$67.31	$2.76	$64.44	$2.80	$65.36	$2.84	$20.39	$0.73
2013	$2.12	$2.12	$68.36	$2.80	$69.08	$2.83	$66.29	$2.88	$67.07	$2.92	$20.80	$0.74
2014	$2.17	$2.17	$70.01	$2.87	$70.89	$2.91	$67.90	$2.95	$68.83	$2.99	$21.22	$0.76
2015	$2.22	$2.22	$71.79	$2.94	$72.82	$2.98	$69.62	$3.03	$70.70	$3.07	$21.65	$0.77
2016	$2.27	$2.27	$73.60	$3.02	$74.80	$3.07	$71.37	$3.10	$72.63	$3.16	$22.09	$0.79
2017	$2.31	$2.31	$75.33	$3.09	$76.72	$3.14	$73.05	$3.18	$74.49	$3.24	$22.53	$0.80
2018	$2.36	$2.36	$77.43	$3.17	$78.61	$3.22	$75.06	$3.26	$76.32	$3.32	$22.99	$0.82
2019	$2.41	$2.41	$79.18	$3.25	$80.52	$3.30	$76.75	$3.34	$78.18	$3.40	$23.46	$0.84
2020	$2.46	$2.46	$80.97	$3.32	$82.48	$3.38	$78.49	$3.41	$80.08	$3.48	$23.94	$0.85
2021	$2.51	$2.51	$82.81	$3.39	$84.49	$3.46	$80.27	$3.49	$82.03	$3.57	$24.42	$0.87
2022	$2.56	$2.56	$84.69	$3.47	$86.55	$3.55	$82.09	$3.57	$84.03	$3.65	$24.92	$0.89
2023	$2.61	$2.61	$87.01	$3.57	$88.65	$3.63	$84.30	$3.67	$86.07	$3.74	$25.43	$0.91
2024	$2.66	$2.67	$88.98	$3.65	$90.81	$3.72	$86.22	$3.75	$88.17	$3.83	$25.95	$0.93
2025	$2.72	$2.72	$91.00	$3.73	$93.02	$3.81	$88.17	$3.83	$90.31	$3.93	$26.49	$0.95
2026	$2.77	$2.78	$93.02	$3.81	$95.23	$3.90	$90.13	$3.92	$92.46	$4.02	$27.03	$0.97
2027	$2.83	$2.83	$95.04	$3.90	$97.44	$3.99	$92.09	$4.00	$94.60	$4.11	$27.58	$0.99

ENERGY MARKETING AND TRADING DIVISION
APRIL, 1998 - EUGENE UNGAR

Document No. 8

Supply Only Resource Plan

Supply Only Resource Plan

Year	New Generation Units Added	New Generation MW Added	New DSM MW Added	Summer Reserve Margin (%)
2001		0	0	16
2002		0	0	19
2003		0	0	21
2004		0	0	19
2005	1 CC	419	0	19
2006	1 CC	419	0	18
2007	1 CC	419	0	18
2008	1 CC	419	0	18
2009	1 CC	419	0	18

Notes: - CC= Combined Cycle Unit
- MW values shown are incremental Summer MW ratings at the generator.

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

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Calculation of Levelized System Average Rate for: **Supply Only Resource Plan**

	Year	Annual Discount Factor 8.98%	Annual Revenue Requirements ($ 000)	Annual Energy Sales (GWh)	Nominal Annual Rate (¢/kWh)	NPV Annual Rate (¢/kWh)	**Nominal Levelized System Average Rate (¢/kWh)**	NPV Levelized System Average Rate (¢/kWh)
1	1998	1.00000	5,882,528	82,307	7.14706	7.14706	**8.3032**	8.303193
2	1999	0.91760	6,078,255	84,668	7.17893	6.58738	**8.3032**	7.619006
3	2000	0.84199	6,245,097	86,513	7.21868	6.07805	**8.3032**	6.991197
4	2001	0.77261	6,469,194	88,332	7.32373	5.65837	**8.3032**	6.415119
5	2002	0.70895	6,597,632	90,195	7.31485	5.18583	**8.3032**	5.886510
6	2003	0.65053	6,973,604	91,930	7.58578	4.93476	**8.3032**	5.401459
7	2004	0.59692	7,207,530	93,729	7.68975	4.59020	**8.3032**	4.956377
8	2005	0.54774	7,508,689	95,439	7.86753	4.30934	**8.3032**	4.547969
9	2006	0.50260	7,800,107	97,171	8.02720	4.03450	**8.3032**	4.173214
10	2007	0.46119	8,066,068	98,929	8.15339	3.76025	**8.3032**	3.829340
11	2008	0.42319	8,340,574	100,758	8.27783	3.50307	**8.3032**	3.513800
12	2009	0.38832	8,622,342	102,794	8.38798	3.25719	**8.3032**	3.224262
13	2010	0.35632	9,298,997	104,647	8.88606	3.16627	**8.3032**	2.958581
14	2011	0.32696	9,758,728	106,523	9.16115	2.99531	**8.3032**	2.714793
15	2012	0.30002	10,094,322	108,366	9.31503	2.79466	**8.3032**	2.491093
16	2013	0.27529	10,455,785	110,255	9.48328	2.61070	**8.3032**	2.285826
17	2014	0.25261	10,828,931	112,091	9.66084	2.44043	**8.3032**	2.097473
18	2015	0.23180	11,188,802	113,942	9.81973	2.27617	**8.3032**	1.924640
19	2016	0.21270	11,533,099	115,436	9.99090	2.12502	**8.3032**	1.766049
20	2017	0.19517	11,808,821	116,782	10.11185	1.97352	**8.3032**	1.620525
21	2018	0.17909	12,081,762	118,159	10.22500	1.83116	**8.3032**	1.486993
22	2019	0.16433	12,354,003	118,729	10.40521	1.70989	**8.3032**	1.364465
23	2020	0.15079	12,545,688	118,729	10.56666	1.59334	**8.3032**	1.252032
24	2021	0.13836	12,787,036	118,729	10.76993	1.49017	**8.3032**	1.148864
25	2022	0.12696	12,982,239	118,729	10.93435	1.38826	**8.3032**	1.054197
26	2023	0.11650	13,206,909	118,729	11.12357	1.29591	**8.3032**	0.967331
27	2024	0.10690	13,455,118	118,729	11.33263	1.21147	**8.3032**	0.887622
28	2025	0.09809	13,715,399	118,729	11.55185	1.13315	**8.3032**	0.814482
29	2026	0.09001	13,959,156	118,729	11.75716	1.05826	**8.3032**	0.747368
30	2027	0.08259	14,229,983	118,729	11.98526	0.98990	**8.3032**	0.685785
						93.12957		93.12957

Levelized System Average Rate (1998-2027, 1998 cents/kwh) = 8.30

Document No. 10

Competing Resource Plans

Competing Resource Plans

	Supply Only Resource Plan			*With DSM Resource Plan*		
Year	New Generation MW Added	New DSM MW Added	Summer Reserve Margin (%)	New Generation MW Added	New DSM MW Added	Summer Reserve Margin (%)
2001	0	0	16	0	54	16
2002	0	0	19	0	79	20
2003	0	0	21	0	77	23
2004	0	0	19	0	78	21
2005	419	0	19	0	79	19
2006	419	0	18	419	79	19
2007	419	0	18	419	77	19
2008	419	0	18	419	78	20
2009	419	0	18	0	77	18

Note: MW values shown are incremental Summer MW ratings at the generator.

Document No.11

Comparison of Annual Reserve Margins and LOLP Values for the Supply Only and With DSM Resource Plans

Comparison of Annual Resrve Margins & LOLP Values for the Supply Only and with DSM Resource Plans

	Supply Only Resource Plan					*With DSM Resource Plan*				
	New Generation MW	New DSM MW	Reserve Margin (%)		Annual	New Generation MW	New DSM MW	Reserve Margin (%)		Annual
Year	Added	Added	Summer	Winter	LOLP	Added	Added	Summer	Winter	LOLP
2001	0	0	16	18	0.089	0	54	16	18	0.076
2002	0	0	19	21	0.009	0	79	20	22	0.006
2003	0	0	21	24	0.004	0	77	23	25	0.002
2004	0	0	19	21	0.024	0	78	21	22	0.011
2005	419	0	19	21	0.006	0	79	19	20	0.007
2006	419	0	18	20	0.011	419	79	19	19	0.012
2007	419	0	18	20	0.006	419	77	19	20	0.005
2008	419	0	18	20	0.005	419	78	20	20	0.003
2009	419	0	18	20	0.004	0	77	18	18	0.007

Note: MW values shown are incremental Summer MW ratings at the generator.

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

Calculation of Levelized System Average Rate for: **With DSM Resource Plan**

	Year	Annual Discount Factor 8.98%	Annual Revenue Requirements ($ 000)	Annual Energy Sales (GWh)	Nominal Annual Rate (¢/kWh)	NPV Annual Rate (¢/kWh)	Nominal Levelized System Average Rate (¢/kWh)	NPV Levelized System Average Rate (¢/kWh)
1	1998	1.00000	5,882,528	82,307	7.14706	7.14706	**8.2875**	8.287540
2	1999	0.91760	6,078,255	84,668	7.17893	6.58738	**8.2875**	7.604643
3	2000	0.84199	6,245,097	86,513	7.21868	6.07805	**8.2875**	6.978017
4	2001	0.77261	6,489,887	88,272	7.35215	5.68033	**8.2875**	6.403025
5	2002	0.70895	6,612,496	90,016	7.34591	5.20785	**8.2875**	5.875413
6	2003	0.65053	6,983,598	91,627	7.62177	4.95817	**8.2875**	5.391277
7	2004	0.59692	7,210,193	93,300	7.72797	4.61301	**8.2875**	4.947033
8	2005	0.54774	7,461,650	94,879	7.86439	4.30762	**8.2875**	4.539395
9	2006	0.50260	7,746,515	96,477	8.02939	4.03560	**8.2875**	4.165347
10	2007	0.46119	7,995,785	98,100	8.15065	3.75899	**8.2875**	3.822121
11	2008	0.42319	8,264,020	99,793	8.28116	3.50448	**8.2875**	3.507176
12	2009	0.38832	8,495,645	101,693	8.35421	3.24407	**8.2875**	3.218183
13	2010	0.35632	9,097,175	103,477	8.79149	3.13257	**8.2875**	2.953004
14	2011	0.32696	9,562,427	105,354	9.07647	2.96762	**8.2875**	2.709675
15	2012	0.30002	9,896,165	107,196	9.23184	2.76970	**8.2875**	2.486397
16	2013	0.27529	10,255,225	109,086	9.40105	2.58806	**8.2875**	2.281516
17	2014	0.25261	10,625,884	110,921	9.57969	2.41993	**8.2875**	2.093518
18	2015	0.23180	10,984,890	112,773	9.74071	2.25785	**8.2875**	1.921012
19	2016	0.21270	11,333,509	114,267	9.91844	2.10960	**8.2875**	1.762719
20	2017	0.19517	11,611,152	115,612	10.04321	1.96012	**8.2875**	1.617471
21	2018	0.17909	11,884,007	116,989	10.15823	1.81921	**8.2875**	1.484190
22	2019	0.16433	12,160,094	117,559	10.34382	1.69980	**8.2875**	1.361892
23	2020	0.15079	12,349,194	117,559	10.50468	1.58399	**8.2875**	1.249672
24	2021	0.13836	12,595,905	117,559	10.71454	1.48251	**8.2875**	1.146698
25	2022	0.12696	12,791,157	117,559	10.88063	1.38144	**8.2875**	1.052210
26	2023	0.11650	13,012,681	117,559	11.06906	1.28956	**8.2875**	0.965507
27	2024	0.10690	13,259,244	117,559	11.27880	1.20572	**8.2875**	0.885949
28	2025	0.09809	13,505,053	117,559	11.48789	1.12688	**8.2875**	0.812946
29	2026	0.09001	13,743,854	117,559	11.69103	1.05231	**8.2875**	0.745959
30	2027	0.08259	14,013,395	117,559	11.92031	0.98453	**8.2875**	0.684492
						92.95400		92.95400

Levelized System Average Rate (1998-2027, 1998 cents/kwh) = 8.29

Document No.13

Comparison of 1994 & 1998 Projections for a CC Unit: Selected Cost & Performance Values

Comparison of 1994 & 1998 Projections for a CC Unit: Selected Cost & Performance Values

	1994 Projection	1998 Projection
Net Summer (MW)	423	419
Capital (Year, $/KW)	689	519
Fixed O&M ($/KW-yr)	19.36	13.74
Variable O&M ($/MWh)	0.13	0.67
Heat Rate (Btu/KWh)	7,246	6,081
EQ. Availability (%)	89	96

Notes:

(1) Dollar values shown are 1994 or 1998 projections (as indicated by column heading) in that year's dollars.

(2) Capital cost is overnight construction cost (w/o escalation or AFUDC).

(3) Fixed O&M values include capital replacement costs.