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August 16, 1999

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RECORDS AND REPORTING

RE: DOCKET NO. 981890-EU

Dear Ms. Bayó:

Enclosed for filing please find the original and fifteen (15) copies of Florida Power & Light Company's Testimony and Exhibits of Roberto R. Dennis in the above-referenced docket.

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Very truly yours,

Matthew M. Childs, P.A.

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CERTIFICATE OF SERVICE
DOCKET NO. 981890-EU

I HEREBY CERTIFY that a true and correct copy of Florida Power & Light Company's Testimony of Roberto R. Denis has been furnished by Hand Delivery*,U.S. Mail this 16th day of August, 1999 to the following:

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By: ______________________
Matthew M. Childs, P.A.

ORIGINAL

BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

DOCKET NO. 981890-EU
FLORIDA POWER & LIGHT COMPANY

AUGUST 16, 1999

GENERIC INVESTIGATION INTO
THE AGGREGATE UTILITY RESERVE MARGINS
PLANNED FOR PENINSULAR FLORIDA

TESTIMONY & EXHIBITS OF:

ROBERTO R. DENIS

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF ROBERTO R. DENIS

DOCKET NO. 981890-EU

AUGUST 16, 1999

Q. Please state your name and business address.

A My name is Roberto Denis and my business address is 9250 West Flagler Street, Miami, Florida 33174.

Q What is your affiliation with Florida Power & Light Company?

A I am employed by Florida Power & Light Company (FPL) as Director of the Resource Assessment & Planning Department.

Q. Please describe your duties and responsibilities in that position as they relate to this investigation.

A. I direct all of the activities of this department. In regard to the specific issues posed in this docket, the relevant activities of the department include: developing FPL's load forecasts, 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 received a Bachelor of Science degree in Electrical Engineering from the Georgia Institute of Technology in 1972. In 1976, I completed an FPL-sponsored/University of Florida course in the field of nuclear power. I have since participated in numerous technical, business and management courses at the University of Auburn, Ohio State University, the Wharton School, and several industry associations.

I am a registered Professional Engineer in the State of Florida, and a member of the Florida Engineering Society and the Institute of Electrical and Electronic Engineers.

Upon my graduation in 1972, I was employed by FPL as a distribution engineer in FPL's Southeastern Division. In 1976, I joined the System Planning Department, where I was promoted to the position of Supervisor of Generation Planning in 1980. In 1982, FPL formed the Load

Management and Customer Generation Department, at which time I was promoted to the position of Manager of that department. In 1985, I joined the Power Supply Department as the Manager of Contracts and Administration. In January of 1989, I was promoted to the position of Director of the System Planning Department. In mid-1998 the name of this department was changed to the Resource Assessment & Planning Department.

Q. Do you participate in any activities of the Florida Reliability Coordinating Council?

A. Yes, I am a member of the Reliability Assessment Group of the Florida Reliability Coordinating Council (FRCC). This group directs the development of technical assessments and makes policy recommendations to the FRCC's Board of Directors.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss my views of this investigation, the regulatory processes that currently exist in Florida to ensure that utilities' plans provide for an adequate and reliable supply of electricity, and why a "shorthand" process based on prescriptive reserve margins does not make sense. I also introduce a description of FPL's resource planning process, briefly discuss how FPL performs the system reliability analysis portion of that process and explain the results of FPL's reliability analyses of its system. Finally, I respond to various issues which have been raised in this docket.

Q. Are you sponsoring any exhibits?

A. Yes. My exhibit consists of the following document:

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

This document is an excerpt from FPL's <u>1999 Ten-Year Power Plant Site Plan</u> which was filed with the Florida Public Service Commission (Commission) in April, 1999.

OBJECTIVES OF THIS INVESTIGATION

Q. What do you understand is the objective of this investigation?

A. It appears that this investigation is centered on one aspect of reliability planning for individual utilities and for Peninsular Florida. Specifically, the investigation focuses on the use of reserve margins for reliability planning and how reserve margin calculations are done. The issue appears to be a consideration of whether to initiate a rulemaking proceeding regarding a uniform reserve margin criterion or standard for individual utilities as well as a standard for Peninsular Florida. I base this opinion on a reading of the issues in this investigation, in particular, issues number 14 and 15.

Q. Should the Commission adopt a uniform reserve margin standard for individual utilities?

A. No, for at least four reasons. First, there is no need for the Commission to act. Second, the imposition of a uniform reserve margin standard for all utilities ignores fundamental differences that exist among individual utility systems. Third, the use of a shorthand approach to evaluating utility reliability; i.e., a uniform standard, may actually frustrate the Commission's ability to review utility reliability. Fourth, attempting to assess or measure system reliability solely through the use of a reserve margin standard is an incomplete exercise. The Commission cannot lose sight of the process by focusing solely on reserve margins, and effectively monitor reliability.

Q. Please explain why you feel there is no need for the Commission to create a uniform reserve margin standard for Florida utilities?

A. The Commission has, for years, effectively tracked and monitored the utilities' reliability planning process. Maintaining system reliability is <u>not</u> a new issue or concern for the Commission. The Commission has actively discharged this responsibility for years without the need for imposing such a standard.

These years of Commission review have evidenced several things. In particular, there is a sophisticated process in place to plan for the electric reliability needs of Florida. In this process, reliability planning is regularly performed by those utilities that are responsible for meeting load. The utilities have employed this process well, and the Commission has done a good job of overseeing it, focusing on reliability - not on whether the resulting reserves are above or below an empirical level reserve margin standard.

This leads me to pose the question of why is there a need for the Commission to act now? Reliability planning is being done by the utilities accountable to the Commission and it is being voluntarily coordinated among utilities. In short, the current process has worked and continues to work. Imposing a reserve margin standard serves no purpose. Therefore, the Commission does not need to act.

Q. You spoke of the Commission having actively reviewed electric system reliability for years and that the current process has worked well. To what were you referring?

A. The Commission not only actively reviews system reliability, but it performs this function regularly. To be clear in that statement, I do not take "system reliability" and "reserve margin" to be synonymous terms. Reviewing system reliability is one of the Commission's most active and consistent roles. It performs this review in at least four separate ways.

First, the Commission requires a periodic, detailed reporting of utilities' resource plans. For a number of years it performed such comprehensive reviews in the annual planning workshops and hearings. The Commission has also had regular reviews of Ten Year Site Plans, even before it had the primary review function. Since 1994 the Commission has assumed the primary review of the Ten Year Site Plans. In this role, the Commission has detailed reporting requirements and extensive follow-up discovery on all aspects of the plan. Through this review, the Commission is familiar with utilities' reliability criteria and resource plans.

In addition, the Commission requires annual reporting of DSM implementation progress, an important part of utilities' resource mixes. The Commission also tracks system reliability and reports its findings to other state agencies.

Second, under the Power Plant Siting Act, a determination of need must be secured for most power plant construction. A critical aspect of such determinations is whether the proposed power plant is needed for system reliability. Through such regular reviews the Commission monitors the reliability of individual utilities and Peninsular Florida. This allows them to regularly review the utilities' reliability criteria, including reserve margins.

Third, the Commission has several periodic dockets/hearings in which planning concerns, including reliability measures such as reserve margin, are addressed. In implementing PURPA, the Commission held a series of hearings to set prices to be paid to cogenerators. Those hearings became known as the Annual Planning Hearings. One of the recurring questions that had to be answered was the utilities' need for power, which turned in part on the utilities' reliability criteria. While such hearings are no longer held, the Commission still has occasion to approve new Qualifying Facilities'(QF) contracts or contract modifications for existing

QFs, an issue being the need for the contract or contract change for reliability purposes. The Commission also reviews DSM cost-effectiveness every five years, a crucial question being the utilities' need for generating capacity resource additions. These periodic DSM proceedings provide yet another opportunity for the Commission to review reliability.

Fourth, over the last decade the Commission has convened several dockets to specifically examine system reliability. Among these dockets are the North Florida Grid proceeding and the 1994 hearings on Planning and Operating Reserves.

Through these extensive proceedings the Commission has regularly tracked and reviewed system reliability. It has acted to approve necessary resource additions – both demand side and supply side. The current system has operated well, avoiding serious reliability problems. It leads me to conclude that there is no need for a uniform reserve margin standard.

Q. Another reason you gave for the Commission not adopting a uniform reserve margin standard is that there are system differences between the utilities. Please elaborate.

A. No two utility systems are identical. There are differences in load, energy usage, and load shape, as well as differences in the type and amount of resources used to meet system demand. There are differences in absolute size. There are differences in interconnections with other utilities. There are differences in the maintenance practices and availability of units. Differences exist in the diversity of fuel supplies, delivery means and backup fuel capabilities. Also, there are differences in the analytical methods, competence and tools used to assess reliability, to name a few. Given the unique aspect of each utility, it is difficult to conceive that a single, uniform reserve margin standard would be equally reasonable for every system. <u>Most importantly, no two systems, even with the same reserve margin, will be equally reliable</u>.

Q. You also testified that adoption of a uniform reserve margin standard may frustrate Commission maintenance of system reliability. Please explain that observation.

A. Currently, the Commission has the ability, in appropriate circumstances, to conduct a comprehensive review and take action to address system reliability concerns. It is not tied to any one reserve margin standard or any one reliability criterion. It may take the bounty of information it has at its disposal and act to address perceived reliability concerns as circumstances may arise. In doing so it can decide whether under the particular circumstances it needs to act and, if it chooses to act, it may select appropriate measures of reliability or other actions specific to the system or the circumstance it is addressing.

Adopting a reserve margin standard may have two significant consequences, each of which limits the flexibility the Commission currently enjoys. First, if a standard is adopted and a utility falls below the standard, that may precipitate Commission action which is unnecessary and inappropriate. Instead of assessing whether there is a reliability problem and its cause, the Commission will be assessing why a standard is not being met. Such an approach limits Commission discretion and changes the nature of its continuing supervision. Second, if an adopted standard is met, it makes it far more difficult for the Commission to act if it determines that under the specific circumstances a more or less demanding measure of reliability is warranted.

When I compare the current case-by-case approach and the associated Commission ability to apply informed judgement with the alternative shorthand approach that changes the focus from whether there is a real reliability concern to whether a reserve margin standard is met, I question the value of this change in approach. It seems to limit the Commission's

<u>flexibility</u> while doing less than the current process to maintain system reliability.

Q. A fourth reason you gave for the Commission not adopting a reserve margin standard was that attempting to gauge reliability through a single standard is an incomplete exercise, please explain your observation.

A. Reserve margin calculation is only one outcome indicator of a system reliability planning process. Many utilities, including FPL, utilize other indicators such as Loss-of-Load-Probability (LOLP) and Expected Unserved Energy (EUE) to capture a more complete view of their system's reliability. Therefore, the imposition of a reserve margin standard will not give a complete picture of a system's reliability.

In addition, on a system such as FPL's, there are other factors that enhance system reliability that are not captured in a reserve margin calculation. Three factors come to mind.

First, FPL has over 600 MW of load which it can "scram" through its existing Residential Load Control Program to enhance system reliability if needed. This load is treated as firm load for purposes of calculating reserve margins, yet it can be effectively used to enhance system reliability. It is a type of cushion which is not reflected in reserve margin calculations but which does contribute to system reliability.

Second, the Commission, in response to the 1989 Winter freeze, has required utilities to develop emergency weather plans, a portion of which includes requests for voluntary customer load reduction and reductions at the company's facilities. Those plans, which have been used before, can be implemented to increase system reliability in times of emergency. For FPL, this is another several hundred MW cushion that is not captured in a reserve margin calculation yet qualitatively increases system reliability.

Third, another reliability enhancing measure available to FPL but not reflected in its reserve margin is voltage reduction. By reducing voltage by 2.5% on its system, an imperceptible amount by most if not all equipment, FPL can reduce the load on its system by about 300 MWs during peak periods. Again, this is not captured in a reserve margin calculation but is a measure that adds to its system reliability.

Q. Should the Commission create a reserve margin standard for Peninsular Florida?

A. No. The same reasons I set forth for individual utilities are equally applicable to Peninsular Florida: a standard is not needed and a standard may limit Commission flexibility and frustrate maintenance of system reliability.

Furthermore, it is difficult to understand how a Peninsular Florida standard would be meaningfully applied and used. If adopted, the exact same set of concerns and problems created by the "statewide avoided unit" concept which was used by the Commission in its implementation of the Cogeneration Rules in the 1980's will exist with a Peninsular Florida standard. It is helpful to remind ourselves of the reasoning by the Commission for abandoning such a statewide approach. The same reasoning will show that a statewide reserve margin standard is unreasonable.

Planning and resource decisions are appropriately made and reviewed at an individual utility level. If there is a Peninsular Florida reliability concern, it is due to one or more individual utilities, not Peninsular Florida as a whole. Attempting to measure Peninsular Florida reliability with a standard, which tells little or nothing about individual utility reliability concerns, may mask reliability concerns.

FPL's RESOURCE PLANNING PROCESS

Q. Please briefly describe FPL's resource planning process.

A. FPL's resource planning process is described in detail in Document No. RRD-1. The process is quite a complex endeavor and takes a number of months to complete each year. However, the process can be described in very general terms as having two main parts. The first part is referred to as a system reliability analysis (which is explained as "Step 1" in Document No. 1). In its system reliability analysis, FPL determines both the timing (in what year) and the magnitude (how many MWs) of FPL's future resource needs. The second part of the resource planning process can be described as an economic analysis. In this part of the work, FPL determines what resources are the most cost-effective to add to FPL's system in order to meet the timing and magnitude of its future resource needs.

The focus of this investigation is clearly on the first part of a resource planning process, the system reliability analysis. Therefore, my testimony will address only this aspect of resource planning.

Q. How should a utility evaluate its system to see if it will be reliable in the future?

A. There is no singular way that is correct for every utility. Each utility should utilize the methodology which it believes is most meaningful for its system. The selection of the methodology will be dependent on factors that affect the reliability of a particular utility's system, such as: geographical and weather diversity, electrical size, number of units, size of units, size of units relative to size of load, reliability of units, electrical interconnections to neighbors, and load characteristics or shape.

Q. Which indicators does FPL use to measure the outcome of the reliability planning process?

A. FPL uses two: a deterministic (reserve margin) and a probabilistic (Loss-of-Load-Probability) indicator. The reserve margin calculation for Summer and Winter is derived using an approach in which the projected firm peak load and projected capacity are compared for the Summer and Winter peak hours. The LOLP calculation is performed using a probabilistic computer model to examine the expected value, in number of days, of FPL not being able to meet load during the year.

FPL utilizes two criteria for these indicators to judge if its system will be reliable in the coming years. These are a minimum reserve margin of 15% during both the Summer and Winter peak load and a maximum Loss-of-Load-Probability (LOLP) of 0.1 days/year. FPL has determined these criteria to be reasonable for its reliability planning process. Furthermore, on a number of occasions the Commission has found FPL's planning methodology and criteria for reserve margin and LOLP to be reasonable for the planning of its system.

FPL uses both of these criteria to judge its system's projected reliability for future years. If in its projections for a given year, neither of the criteria are exceeded, and there are no other reasons for concern, then the system is judged to be reliable for that year and no new resource additions are planned which address that year. However, if one or both of the criteria are exceeded for a given year, then the magnitude (i.e., the number of MWs) of the resource which should be added to address that year in order for the criteria not to be exceeded is calculated. Depending upon the magnitude of the requirement (MWs) in question, and on the length of time for which a criterion is not met (for example, for one season only or for several years), a decision is made as to what resources, if any, should be added.

Q. Why does FPL use two indicators to evaluate the reliability of its system?

A. Each indicator takes a different perspective and considers different characteristics of the system. One is quantitative (reserve margin) and the other is qualitative (LOLP). Each one has its strengths and weaknesses, but in combination, this dual approach is more conservative and robust than using a single indicator. As currently is the case, LOLP on FPL's system is extremely low (which means that FPL's system is very reliable from this perspective) and, if used alone, would result in very low reserve margins.

Therefore, the reserve margin criterion is currently driving FPL's future needs. This criterion is projected to be exceeded before the LOLP criterion. This is largely due to improvements in availability/reliability in FPL's existing generating units which serve to lower projections of LOLP.

Q. What are the key components of a reserve margin calculation?

A. Calculations of projected reserve margins utilize 5 basic components:

1) the amount of capacity (MW) available at the peak hour from the utility's own generating units;

2) the amount of capacity (MW) available at the peak hour from qualifying facilities and independent power producers with which the utility has a firm capacity contract;

3) the amount of capacity (MW) available at the peak hour resulting from the utility's firm import capacity contracts;

4) the peak hour load (MW) served by the utility <u>before</u> the effects of any demand side management (DSM) programs are accounted for (DSM encompasses load management, and interruptible rate programs and incremental conservation,.); and,

5) the peak hour capability (MW) of the utility's DSM programs.

Q. How does FPL use these components to calculate reserve margins?

A. FPL utilizes these components to calculate reserve margins using the following formula:

$$RM = [(C - L) / L] * 100$$

where:

"RM" -- Is defined as the utility's percent planned reserve margin;

"C" -- Is defined as the aggregate sum of the rated dependable peak-hour capabilities of the resources that are expected to be available at the time of the FPL's annual peak.

"L" -- Is defined as the expected firm peak load of the system for which reserves are required.

This formula is the same as that defined in F.A.C. Rule 25-6.035.

Q. Does FPL's resource plan meet FPL's planning criteria?

A. Yes. FPL's current resource plan (as reflected in FPL's 1999 Ten Year Power Plant Site Plan) is not only projected to meet the 15% minimum Summer reserve margin criterion for each of the next 10 years, it is projected to exceed it for 9 of those 10 years. The plan also is projected to exceed the 15% minimum Winter reserve margin criterion for all 10 years and easily meet the LOLP criterion of a maximum of 0.1 day/year for each of the 10 years.

Q. Are the number of times per year FPL uses load management an indication of the reliability of the system?

A. No, not at all. FPL's approved load management programs supply a cost-effective resource which FPL expects to use as needed. FPL's expected annual frequency of use may differ substantially from that of another utility since each may have a different level of reliance on load management. For that reason, the fact that two utilities may have different expectations of load management usage does not, by itself, mean that one system is more reliable than another.

In addition, FPL expects the annual frequency of use of load management to vary as plant outages and nuclear refueling schedules, weather, and customer demands change from one year to the next. To-date, load management has performed as planned. Furthermore, those customers willing to have their load managed have benefited through payments made from the savings achieved from capacity avoided.

ISSUES SPECIFIC TO THIS DOCKET

Q. What is the appropriate methodology, for planning purposes, for calculating reserve margins? (Issue 1)

A. FPL believes that the formula which it uses for calculating reserve margins, and that I previously discussed, is the appropriate way to calculate reserve margins for planning purposes or otherwise. It is identical to the formula used by the Commission and defined in F.A.C. Rule 25-6.035. It is also the electric utility industry's standard way of calculating reserve margin.

Q. What is the appropriate way to evaluate reserve margins? (Issue 2)

A. A reserve margin can be "evaluated" in two ways. First, there is a test against the standard. A utility's projected reserve margin for a given year can be evaluated versus the utility's reserve margin planning criterion (for example, a 15% minimum criterion). If the utility's projected reserve margin equals or exceeds the planning criterion, then the utility's electrical system is deemed to be reliable for that year. However, if the utility's projected reserve margin falls below the planning criterion, then the utility's electrical system may be deemed not to be reliable for that year without additional resources. I say "may be" because, as previously discussed, this depends on the cause and magnitude of the deficiency, the alternatives and costs of mitigating the shortfall, resource additions the utility may be undertaking in subsequent periods to restore the reserve margin, and on the short term operating measures which may be undertaken which could result in a different criterion if such measure were sustainable in the long term.

The second is a test of the adequacy of the standard. This is to ensure that if a utility's resource plan meets the criterion, reliable electrical service will be maintained. Reserve margin planning criteria are generally developed and evaluated through years of operating experience to see what level of reserves is really needed in practice given the unique characteristics of a utility.

The adequacy of a reserve margin criterion can also be tested empirically. One empirical way to test this is to determine historical levels of accuracy in projecting the components of a reserve margin calculation and apply those historical accuracy levels to the current projected reserves. This is the methodology which has been used by the FRCC to test the adequacy of its reserve margin criterion. An explanation of this methodology is found in Mr. Villar's testimony for the FRCC in this docket.

For its resource planning purposes, FPL believes that minimum 15% reserve margin (plus a maximum of 0.1 day/year LOLP) are adequate criteria for maintaining reliable electric service <u>for its system</u>.

Q. How should the individual components of a reserve margin planning criterion be defined in regard to: capacity available at peak, seasonal firm peak demand, and non-firm load at the end of its contract/tariff period? (Issues 3 A & B)

A. In regard to reserve margin calculations, the capacity available at peak values should represent the capacity of a utility's generating units which can be reliably counted on during the Summer and Winter peak hours, plus the firm capacity value from the utility's firm capacity purchase contracts. Non-firm capacity values from purchases should not be included in a reserve margin calculation because they are not committed to meeting the utility's peak. It is simply wrong to include capacity which is not committed under contract in reserve margin calculations. The Commission, in established precedent, has directed utilities in Florida not to depend on As-Available sources of power for capacity benefits.

The seasonal firm hourly peak demand values used in reserve margin calculations should be the most probable projected peak hourly load minus the DSM capability for that peak hour.

This DSM capability for the peak hour will often be comprised, at least in part, of non-firm load programs such as load management programs, interruptible rate programs, and/or curtailable rate programs. (FPL's non-firm load capability consists of both residential and commercial/industrial load management programs. FPL does not count curtailable load in its non-firm capability.)

In regard to the question of how the non-firm load capability should be treated in reserve margin calculations in light of the fact some of the participating customers may be near the end of their contract or tariff period, the answer must be a utility- specific one. Projections for non-firm load programs should include considerations of participant drop out and sign up rates (FPL's projections do consider this). The question of how significant it may be for a utility that a number of non-firm load participants may be near the end of their contract or tariff period depends greatly upon whether a utility has a ready supply of "replacement" customers for any existing participants which may drop out as well as how long the contractual commitments are for various non-firm load programs.

For example, residential load management customers typically have a very short (in terms of days, not years) tariff period which "binds" the participating customer to the program. Therefore, utilities have faced this reality since the first day of residential load management programs. However, the concern over large numbers of participating residential customers dropping out is minimal if one or more of the following conditions exist: the utility has a large number of customers waiting to sign up for the program, the program has experienced a small dropout rate over time, and/or the frequency of use of the program is not expected to significantly change.

On the other hand, commercial/industrial load management programs typically have longer contractual commitments for their participants. (FPL, for example, has a 5-year notice provision for its Commercial/Industrial Load Control program before a participant can drop out of the program.) This longer contractual commitment minimizes concern over projected non-firm load amounts not being available in the future when needed since it provides ample time to adjust resource plans accordingly.

Q. Should a reserve margin planning criterion be determined on an annual, seasonal, monthly, daily, or hourly basis? (Issue 3 C)

A. As previously defined, a reserve margin criterion for long-term resource planning should be based on the seasonal hourly peak for which reserves are required.

Q. How should generating units be rated for inclusion in a percent reserve margin planning criterion? (Issue 4)

A. For reserve margin calculations, the rating (MW) which should be used for generating units is the capacity which can be reliably counted on during the utility's seasonal peak hour. Certain units may be able to be "peaked" for a few hours as needed to provide more than the normal operating capacity of the unit. If the utility believes that occasionally obtaining this peak output is possible without unduly affecting the reliability of the units, then the utility may wish to include this peak capacity rating in its reserve margin calculations. FPL does include peak ratings in its reserve margin calculations. This practice extracts value from the generation investments supported by our customers and helps keep electric rates low.

Q. Should there be a limit on the ratio of non-firm load to MW reserves in a utility's resource plan? (Issue 6)

A. This question can only be answered on a utility-specific basis. Each utility needs to determine if additional non-firm load is cost-effective on its system. As long as the answer to this question is "yes", then there is no need to limit the addition of more non-firm load.

For example, FPL believes it is nearing the point at which more non-firm load will not produce the same amount of demand reduction as previous non-firm load signups because the firm load shape is becoming flatter. This means that, once this point is reached, the additional increments of non-firm load will not be cost-effective. Therefore, FPL has chosen to sign up significantly less non-firm load in the coming years than it has recently signed up. (This issue was described in detail in the testimony of S. R. Sim in Docket No. 971004-EG, DSM Goals Docket.)

In addition, the very existence of the Commission's DSM Goals rules argues against placing a limit on any type of DSM program (including non-firm load programs) which is based on anything other than cost-effectiveness. The DSM Goals rules (Rule 25-17.001 F.A.C) instruct utilities to aggressively implement cost-effective DSM. Thus, as long as additional non-firm load is cost-effective, any other type of limit that might be placed on non-firm load would run counter to the instructions given to the utilities by the Commission's DSM Goals rules.

Also, a limitation on cost-effective non-firm load would be inconsistent with the Commission's Non-firm Service Rule, which is designed to maximize cost-effective load control. The Commission's implementation of that rule has been to encourage the expansion of non-firm service. The Commission has regularly approved non-firm service offerings, and the growth of such offerings has been regularly reported to the Commission. In short, the Commission has fostered the offering of non-firm service by approving cost-effective offerings. The rule has operated as intended; it has avoided or deferred costly power plants; it has increased system reliability, and it has provided a significant amount of savings to the customers.

Q. Should there be a minimum amount of supply side resources when determining reserve margins? (Issue 7)

A. This question is essentially the "flip" side of the previous question and, again, the question can only be answered on a utility-specific basis. A utility's answer will be based both on the cost-effectiveness of supply side versus DSM options on its system and on how much confidence the utility has in the various types of options. One utility may still have significant amounts of cost-effective DSM available to it while another utility will have less remaining cost-effective DSM potential. Likewise, one utility may have a high level of confidence in its DSM resources and may choose to place a heavier reliance on them than would another utility which had less confidence in those same type of resources on its system. There is no one correct level of supply side versus DSM resources for all utilities.

In addition, as previously mentioned, the Commission's DSM Goals rules clearly intend for the utilities <u>not</u> to require a certain "quota" of supply side resources if additional DSM (which would result in an amount of supply side capacity less than the quota) is projected to be cost-effective.

Q. What, if any, planning criteria should be used to assess the generation adequacy of individual utilities? (Issue 8)

A. Once again, the answer to this question must be utility-specific. Each utility should utilize a planning methodology and criteria which it believes best evaluates its system and how the system will be operated. The Commission can and should examine such criteria, as it has in the past, and opine on the planning criteria's suitability for reliability planning purposes.

Q. Should the import capability of Peninsular Florida be accounted for in measuring and evaluating reserve margins and other reliability criteria for individual utilities? (Issue 9)

A. Yes, but only to the extent that the import capability is relevant to the reliability criterion in question.

For example, in regard to reserve margin calculations, the total import capability is not directly relevant. What is relevant is the amount of firm capacity imports from outside the peninsula which the utility has contracted. Only this amount of the total import capability should be included in the utility's reserve margin calculations. Consequently, the total import capability of the peninsula is not a factor in reserve margin calculations.

In regard to LOLP calculations, the total import capability value may be more important. The difference between the total import capability of the peninsula and the amount of that capability which is already accounted for in firm capacity contracts represents an additional amount of non-firm capacity which may be available from outside the peninsula. This additional capacity, or some part thereof, may be accounted for in LOLP calculations based on the projected likelihood that this assistance capacity will be available when needed.

Q. Does FPL appropriately account for historical Winter and Summer temperatures when forecasting seasonal peak loads for purposes of establishing a percent reserve margin planning criterion? (Issue 10)

A. Yes. FPL uses a system-wide temperature composite of its entire service territory for predicting Summer and Winter peaks. To develop this system-wide temperature composite, hourly weather data from four primary weather stations, Miami, Daytona Beach, Ft. Myers and West Palm Beach has been gathered dating back to 1948. The four weather stations provide sufficient geographic coverage to reflect differences in weather conditions across the service territory. The weighted average of the four weather stations provides a system-wide composite temperature used in the peak forecasting models. The process for arriving at Summer and Winter peak representative temperatures are identical.

Between 1948 and 1998, the average of the system-wide Winter peak day minimum temperatures is 37.7 degrees Fahrenheit. However, in several years during this period, Florida did not experience temperatures low enough to generate substantial Winter peak load. If these years are disregarded when calculating the average Winter peak minimum temperature, the system-wide minimum temperature falls to 34.5 degrees Fahrenheit. When projecting Winter peak loads, FPL assumes that on the Winter peak day the minimum temperature will be 34.5 degrees Fahrenheit. The assumed temperature change from 37.7 to 34.5 degrees Fahrenheit first occurred in the 1997 Ten-Year Power Plant Site Plan.

The historical Summer maximum temperatures are more stable than the Winter minimum temperatures, in the sense that there is very high degree of certainty there will be a sufficiently high temperature to generate a substantial Summer peak load. The long term average Summer peak day maximum temperature is 92.7 degrees Fahrenheit. FPL is currently evaluating using a subset (the last twenty years) of the Summer temperature data series, as there is mounting evidence that it may be more reflective of current temperature trends. The average of such abbreviated temperature data is 94 degrees Fahrenheit. Any changes in this methodology will be noted in future Ten-Year Power Plant Site Plan reports to the Commission.

Q. What percent reserve margin is currently planned for FPL and is it sufficient to provide an adequate and reliable source of energy for operational and emergency purposes in Florida? (Issue 12)

A. FPL's 1999 Ten Year Power Plant Site Plan (revised) shows the following Summer and Winter reserve margins (the corresponding LOLP levels are also shown):

	Projected Reserve Margin		
Year	Summer	Winter	LOLP
1999	16%	20%	0.022
2000	15%	19%	0.028
2001	16%	18%	0.076
2002	20%	22%	0.006
2003	23%	25%	0.002
2004	21%	22%	0.011
2005	19%	20%	0.007
2006	19%	19%	0.012
2007	19%	20%	0.005
2008	20%	20%	0.003

These projected reserve margins always meet, and almost always exceed, FPL's reserve margin criteria of a minimum of 15% for Summer and Winter. Also, the projected LOLP levels are always better than the LOLP standard of 0.1 day/year. Therefore, these projections indicate that FPL's resources should provide for an adequate and reliable source of electricity over this time period.

Q. Should the Commission adopt a reserve margin standard for individual utilities in Florida? If so, what should be the appropriate reserve margin criteria for individual utilities in Florida? (Issue # 14)

A. No, for the many reasons I have stated. The Commission has already established a <u>minimum</u> reserve margin threshold of 15% for individual utilities by their rulings in Docket No. 940345-EU. This is a <u>minimum</u> standard only meant as a safety net or backstop, and therefore appropriate for all utilities. The Commission should not now adopt either changes to this minimum or establish a uniform reserve margin criteria.

Q. Should the Commission adopt a maximum reserve margin criterion or other reliability criterion for planning purposes; e.g., the level of reserves necessary to avoid interrupting firm load during weather conditions like 01/17/77, 01/13/81, 01/18/81, 12/19/81, 12/25/83, 01/21/85, 01/21/86, and 12/23/89? (Issue 16)

A. No, there is no need. Rather than establishing an artificial reserve margin standard, if there is concern that a utility's load forecasting process is inadequate or that operating procedures during weather extremes are inadequate, that should be the focus of inquiry by the Commission. In other words, the Commission should address the root cause of the problem and not mask a symptom by merely setting a reserve margin criterion that makes the problem look like it has disappeared.

I should also note in responding to this issue that of the eight events over the past twenty-two years, all but the last two events occurred prior to Florida's electric grid being firmly interconnected to the rest of the Eastern United States. The second event on 12/23/89, the infamous "Christmas Freeze of 89" resulted from an extreme set of conditions, some controllable and predictable, others not. In any event, the Commission found, after its investigation of the incident, that it resulted from an unfortunate confluence of events that were best addressed by better operational and emergency procedures, not by the addition of extra capacity (i.e., higher reserve margin criterion).

Q. **Can out-of-Peninsular Florida power sales interfere with the availability of Peninsular Florida reserve capacity to serve Peninsular Florida consumers during a capacity shortage? If so, how should such sales be accounted for in establishing a reserve margin standard? (Issue 18)**

A. No, they should not interfere. All firm capacity sales, whether inside or outside Florida, are already accounted for in utility resource planning. These sales are part of the "L" term of the reserve margin formula set forth in 25-6.035 FAC. Therefore, firm sales don't complicate matters if a capacity shortage arises. Non-firm capacity sales, whether inside or outside Florida, can and should (by definition) be discontinued in case of a capacity shortage within Florida.

Q. **Based on the resolution of all of the issues raised in this docket, what follow-up action, if any, should the Commission pursue? (Issue 19)**

A. FPL believes that both its system, and the composite electric system for Peninsular Florida, are projected to be quite reliable over the next decade. FPL believes the Commission should take no special action, but continue to monitor the reliability planning process of utilities and the effect of the electric grid in Florida as it has in the past.

However, if the Commission decides that it has some concerns that justify remedial action, then FPL believes that the Commission should proceed either to rulemaking on industry-wide concerns or initiate specific action to address individual utility concerns. In a rulemaking, the Commission should strive to address the specific circumstances of each individual utility for any revised standard that is developed. The Commission should also ensure that an appropriate transition period exists for the utility or utilities affected to meet any revised standard. In a utility specific proceeding, the utility or utilities involved should be given the opportunity to address the Commission's specific concerns and proposed actions.

Q. Does this conclude your testimony?

A. Yes, it does.

OVERVIEW

Of FPL's

IRP Process

RRD-1
Docket No. 981890-EU
FPL Witness: R. R. Denis
Exhibit _____
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CHAPTER III

Projection of Incremental Resource Additions

III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL developed an integrated resource planning (IRP) process in the early 1990's and has since utilized the process 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 the IRP process work. This section discusses how FPL applied this process in its 1998 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;

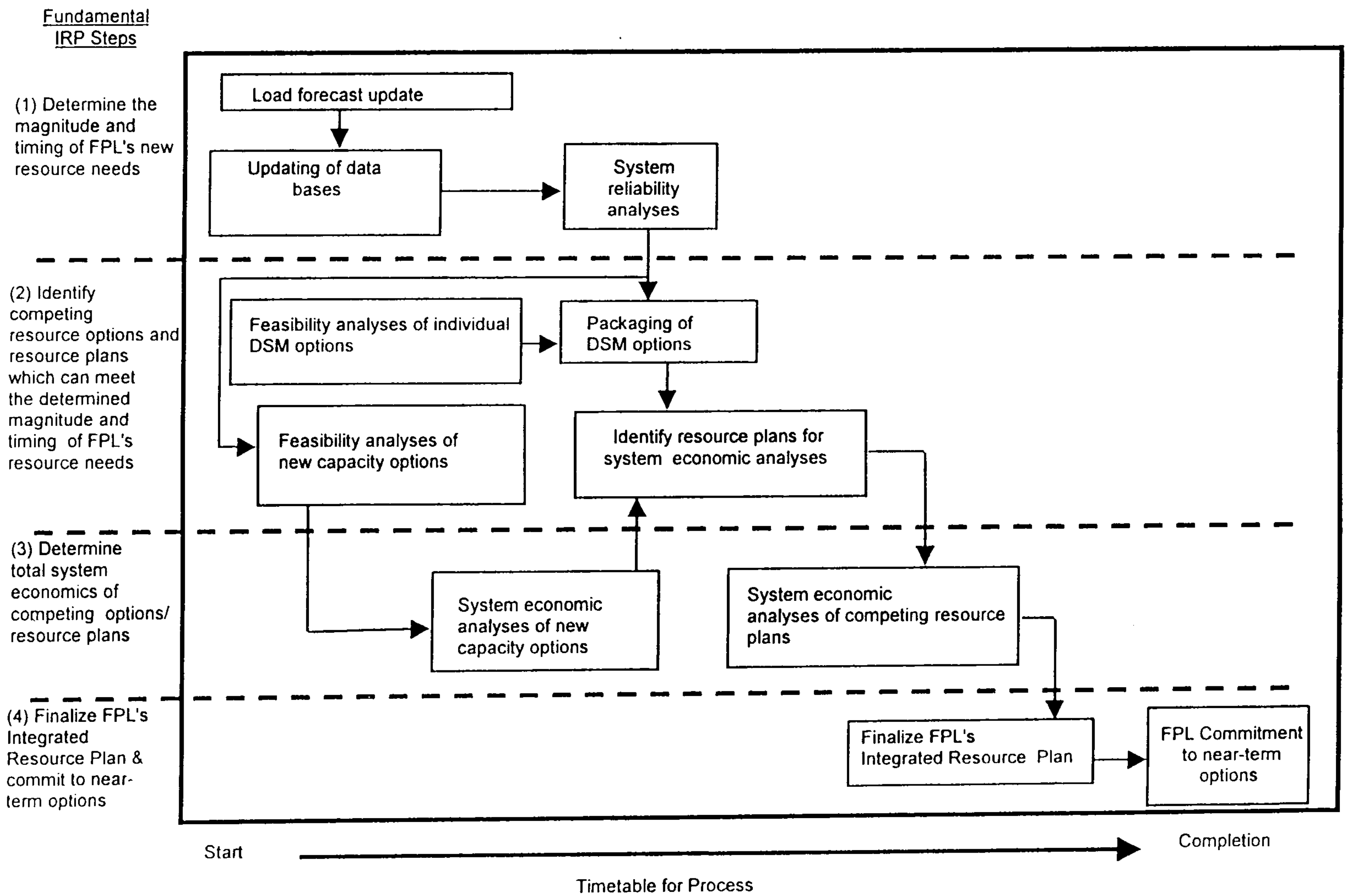
Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e. identify competing options and resource plans;

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 the 4 steps.

Overview of FPL's IRP Process



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

Figure III.A.1

Step 1: Determine the Magnitude and timing of FPL's Resource needs:

The first of these four resource planning steps – determining the magnitude and timing of FPL's 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 forecasted loads, but with other information as well which is used in many of the fundamental steps in resource planning. Examples of this new information include delivered fuel price projections current financial and economic assumptions, power plant capability and reliability assumptions, etc. Among the assumptions FPL made at the start of its 1998 IRP work were one involving near-term generation capacity additions and one involving DSM.

FPL committed in 1998 to repower both existing steam units at its Ft. Myers plant site and two of the three existing steam units at its Sanford plant site. These two repowering efforts will add significant capacity increases to FPL's system and will greatly increase the efficiency of the capacity now at those two sites. The repowered Ft. Myers capacity is scheduled to come in-service by January, 2002. Combustion turbines, which are components of the repowering effort, will come in-service at Ft. Myers during 2001 and will result in net capacity increases to the FPL system during portions of that year. A similar schedule is planned for Sanford with its repowered capacity coming in-service January, 2003 and combustion turbine components of the repowering work becoming operational during 2002. [1] As a result of this commitment, FPL assumed that these capacity additions resulting from the Ft. Myers and Sanford repowerings were a "given" in its 1998 resource planning work.

Since 1994, FPL's resource planning work has also used the DSM MW called for in FPL's approved DSM goals as a "given" in its analyses. However, FPL filed in 1999 for

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[1] FPL's 1998 IRP identified that Sanford units #3 and #4 would be repowered. At the time of publication of this document, subsequent to FPL's 1998 IRP, FPL is reexamining its Sanford repowering plan. This reexamination is based on newly developed technical information which focuses on whether it would be more advantageous to repower units #4 and #5 rather than units #3 and #4. Such a change in the Sanford repowering plan would add approximately 240 MW Summer capability from the Sanford site beyond what would be gained from repowering units #3 and #4. If such a change is made to the Sanford repowering plan during 1999, it will be communicated to the appropriate state agencies and reflected in FPL's 2000 Site Plan filing.

new DSM goal levels. Consequently, FPL's 1998 resource planning work assumed that FPL's current DSM efforts would continue only through the year 2000 (i.e., only during the time it takes to have new goals set and to have DSM program revisions implemented in the field.) FPL assumed that no additional DSM was a "given" after 2000 in order to allow DSM to compete with new generation options for a role in the 1998 resource plan. The first place in which much of this updated information and assumptions are 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; criteria which are commonly used throughout the utility industry. FPL also used a third reliability criterion in 1998: a minimum 15% Winter reserve margin criterion. This third criterion was used in FPL's 1998 planning work due to concern regarding reserves available during extreme Winter peak loads.

Historically, two types of methodologies, deterministic and probabilistic have been employed in system reliability analyses. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common 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 methods do not take into account probabilistic events such as: unit reliability; unit size (i.e., two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit); 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. During Step 2, 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. In similar fashion, individual DSM options were evaluated to determine their potential cost-effectiveness and their achievable potential for each year after 2000.

The individual new resource options, both new generating units and DSM, are then "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's new 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 1998, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs were identified. 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 resource options have been identified, and these resource 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 resource options into resource plans using linear programming techniques and the EGEAS (Electric Generation Expansion Analysis System) computer model from the Electric Power Research Institute (EPRI) and Stone & Webster Management Consultants, Inc. The EGEAS model is also used to perform the economic analyses of the resource plans.

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).

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 1998 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 1998 resource plan would be. This plan is presented in the following section.