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REGISTERED LIMITED LIABILITY PARTNERSHIP

Steel Hector & Davis LLP
215 South Monroe, Suite 601
Tallahassee, Florida 32301-1804
850.222.2300
850.222.8410 Fax
www.steelhector.com

Charles A. Guyton
850.222.3423

September 9, 2003

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VIA HAND DELIVERY

Ms. Blanca Bayó, Director
Division of the Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Re: Objections to Florida Power & Light Company's 2003 Capacity Request for Proposal by the Florida Partnership for Affordable Competitive Energy Docket No. 030884-EU

Dear Ms. Bayó:

Enclosed for filing please find an original and seven copies of the following:

1. Response of Florida Power & Light Company ("FPL") to Objections to FPL's 2003 capacity Request for Proposal; and

2. FPL's Motion to Exclude PACE from Bid Rule Objection Process.

If you or your Staff have any questions regarding this transmittal, please contact me at (850) 222-2300.

Respectfully,

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Charles A. Guyton
Attorney for Florida Power & Light Company

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Objections
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Objections to Florida Power & Light Company's 2003 Capacity Request for Proposal by the Florida Partnership for Affordable Competitive Energy	))))	**Docket No. 030884-EU** **Filed: September 9, 2003**

RESPONSE OF FLORIDA POWER & LIGHT COMPANY

September 9, 2003

R. Wade Litchfield
Senior Attorney
Florida Power & Light Company
P.O. Box 14000
700 Universe Boulevard
Juno Beach, Florida 33408

John T. Butler
Steel Hector & Davis LLP
200 S. Biscayne Boulevard
Suite 4000
Miami, Florida 33131

Susan Clark
Radey Thomas Yon & Clark P.A.
313 N. Monroe St., Suite 200
Tallahassee, Florida 32301

Ken Hoffman
Rutledge, Ecenia, Purnell & Hoffman, P.A.
215 S. Monroe St., Suite 420
Tallahassee, Florida 32302

Charles A. Guyton
Elizabeth Daley
Steel Hector & Davis LLP
Suite 601, 215 S. Monroe St.
Tallahassee, Florida 32301

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Objections to Florida Power & Light Company's 2003 Capacity Request for Proposal by the Florida Partnership for Affordable Competitive Energy	))))	**Docket No. 030884-EU** **Filed: September 9, 2003**

RESPONSE OF FLORIDA POWER & LIGHT COMPANY

Pursuant to Florida Administrative Code Rule 25-22.082(12), Florida Power & Light Company ("FPL") is filing its responses to the objections to FPL's August 25, 2003, Request for Proposals ("RFP") filed on September 4, 2003, by the Florida Partnership for Affordable Competitive Energy ("PACE"). FPL responds as follows:

INTRODUCTION

The Florida Public Service Commission ("Commission" or "FPSC") has received 14 objections to the terms of FPL's RFP. Those objections have not been submitted by potential participants in the RFP process but rather by PACE, which cannot be a participant. FPL is separately filing a motion to exclude PACE from the Bid Rule objections process, as PACE is not a "potential participant" in FPL's RFP within the meaning of Rule 25-22.082, Florida Administrative Code (hereinafter referred to as "the Bid Rule"), and alternatively, PACE does not meet organizational standing requirements. However, since it is unclear how the Commission will dispose of FPL's motion, and in the interest of facilitating intelligent dialogue and debate regarding the allegations that PACE has made and is likely to continue to pursue throughout this process, FPL is responding in this document to PACE's objections.

Before addressing the dubious "merits" of PACE's individual objections, three initial observations are warranted. First, the standard the Commission has set forth in the Bid Rule for this objection process is whether the RFP violates the Bid Rule. It is not, as PACE would have the Commission consider, whether the terms of the RFP are consistent with the Commission's

Mission Statement, a document that has not been subjected to the rulemaking requirements and procedures of the Administrative Procedure Act ("APA") and is not included or mentioned in any form in the Bid Rule. Second, FPL encourages a very careful reading of PACE's objections, because the document is liberally populated with outright misrepresentations and overstatements, not to mention unsupported conclusory statements and hyperbole, such that FPL has insufficient time or space to correct each such instance. Third, PACE has requested far more relief than the Commission contemplated providing when it adopted this unique procedure.[1] An elaboration on each point is warranted.

Standard Of Review

The portion of the Bid Rule that creates this unique procedure is very specific as to appropriate objections:

> (12) A potential participant may file with the Commission objections to the RFP limited to specific allegations of violations of this rule within 10 days of the issuance of the RFP. The public utility may file a written response within 5 days. Within 30 days from the date of the objection, the Commission panel assigned shall determine whether the objection as stated would demonstrate that a rule violation has occurred, based on the written submission and oral argument by the objector and the public utility, without discovery or an evidentiary hearing.

The only issue for resolution is whether the RFP terms violate the Bid Rule. The standard is not whether an RFP term violates or is consistent with the Commission's Mission Statement, which has not been promulgated as a rule subject to APA rulemaking procedures.[2]

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[1] In considering the relief requested, the Commission should recognize the extent to which it may determine parties' substantial interests in this rule-created procedure, which may not comport with the requirements of Sections 120.569, 120.57(1) or 120.57(2), Florida Statutes.

[2] Any use or attempted construct of the Bid Rule to promote competition in the electric utility industry is misplaced. The Commission has been given explicit authority to promote competition within the telecommunications industry. See Section 364.01(4)(d), Florida Statutes. Comparable legislative authority regarding public utilities has not been granted in Chapter 366.

Throughout its pleading, beginning in its "Introduction" and ending in its "Conclusion," PACE attempts to weave a connection between the Commission's Bid Rule and the Commission's Mission Statement that is inaccurate and improper. PACE initially argues that the Commission adopted its first Bid Rule "consistent with this mission," (PACE Objections at 1) when, in fact, the Commission's Bid Rule predates the Commission's Mission Statement by many years. PACE also argues that the Bid Rule's intent is "to foster competition in Florida's electric generation supply market." PACE Objections at 26. Of course, this misrepresentation is easily exposed by looking to the Bid Rule's explicit expression of intent:

> (1) Scope and Intent. The intent of this rule is to provide the Commission information to evaluate a public utility's decision regarding the addition of generating capacity pursuant to Section 403.519, Florida Statutes. The use of a Request for Proposals (RFP) process is an appropriate means to ensure that a public utility's selection of a proposed generation addition is the most cost-effective alternative available.

Rule 25-22.082(1), F.A.C.

The Bid Rule's intent is not as PACE misrepresents, "to foster competition in Florida's electric generation supply market." That is PACE's purpose and intent. The Bid Rule was not passed to protect PACE and its members. The Bid Rule was passed to protect utility customers by creating a solicitation process that resulted in the utility's selection, on behalf of its customers, of the most cost-effective generating option. The Commission in adopting the Bid Rule was indifferent as to the type of entity that builds the most cost-effective alternative; it just wanted the utility to select the most cost-effective unit. PACE's entire Objection, with its repeated references to promoting competition in Florida's energy markets as the Commission's espoused public policy purpose (See PACE Objection at 1, 7, 25, 26), is a distortion of the Commission's Bid Rule and its underlying intent.

If PACE is serious about competition, then its members need to become competitive rather than attempting to distort the Bid Rule to their advantage. PACE repeats its hackneyed observation that since the Bid Rule was adopted no IPP unit has been selected in an Investor Owned Utility ("IOU") RFP, as if this were an indictment of Florida's IOUs. See PACE Objection at 1, 2. In fact, this is an indictment not of utilities but of the IPPs' lack of competitiveness. Each utility RFP about which PACE complains was reviewed by the Commission, and in each instance the Commission found that the RFP was fair and that the utility option was the most cost-effective. Unless PACE is arguing that the Commission has failed to do its job, PACE's observation is nothing more than an admission that to date the IPP industry has yet to demonstrate it is competitive. PACE would have you interpret the Bid Rule to protect its interests rather than the interests of utility customers. FPL respectfully urges the Commission to reject this misinterpretation of the Bid Rule.

<u>PACE's Overreaching</u>

As previously noted, PACE's Objection is full of misrepresentations, overstatements, hyperbole and unsupported, conclusory statements. Two particularly egregious examples stand out as examples of why the Commission needs to hold PACE's representations to a high scrutiny. At page 14 of its Objection, PACE misstates that "FPL affirms that exceptions taken to the PPA will be penalized in the non-economic evaluation." If one looks at the transcript PACE cites (Exhibit 1 to PACE's Objections, page 25), it is clear that FPL made no such affirmation. Instead, FPL stated, not once but twice, that exceptions will be assessed for risk. Having turned up with its trial attorney and a stenographer to cross-examine FPL's personnel during a workshop that was not intended to provide discovery for objections but to assist potential bidders in formulating bids, PACE got the answer it did not want and nonetheless misrepresented to the Commission what was actually said. PACE's factual assertions warrant careful scrutiny.

Similarly, PACE argues that FPL is reserving transmission capacity for future capacity options. See PACE Objection at 16 - 18. This is a gross misstatement of what FPL set forth in its RFP. FPL is not reserving or attempting to reserve any transmission capacity for future additions in its RFP. FPL is addressing a 2007 load/generation imbalance in Southeast Florida that needs to be addressed in 2007. In doing so, it is properly assigning transmission related costs to the units that will compete to meet FPL's 2007 need. FPL also accurately noted that if the imbalance was addressed, this may free import capacity for future unit additions, including additions that might improve FPL's fuel diversity. That is not an attempt to reserve transmission for the future. Moreover, it should be noted that any future capacity additions might well be IPP units as well as FPL units.

Rather than fairly construing FPL's attempt to fully disclose its best available system information regarding location preference and known transmission constraints, as explicitly contemplated by the amended Bid Rule (see Rule 25-22.082(5)(g), F.A.C.), PACE grossly misconstrues FPL's good-faith effort into an alleged anticompetitive motive. PACE's hyperbole warrants careful scrutiny.

PACE's Faulty Legal Analysis

FPL also respectfully urges caution in entertaining the extensive remedies sought by PACE in this unique rule-created procedure. PACE would have the Commission issue an order determining parties' substantial interests by excluding or substituting RFP terms. However, this is not a proceeding to determine substantial interests. It is not a Section 120.57(2) proceeding, as there are clearly disputed issues of material facts raised by PACE for resolution, and this is not a

Section 120.57(1) proceeding, as the Commission has precluded by the terms of the Bid Rule an evidentiary hearing. FPL urges caution in embracing PACE's implicit underlying legal analysis that would have the Commission taking action affecting substantial interests in a proceeding that is not set forth in the APA.

Introduction to FPL's Responses

The remainder of this document is organized in four sections. Section I addresses objections made to FPL's Minimum Requirements. These are addressed separately because they are mandatory requirements, all of which FPL believes are necessary to protect FPL's customers. Section II addresses the objection made to negotiable RFP terms and conditions. Section III addresses objections pertaining to FPL's evaluation methodology. Section IV addresses PACE's two objections regarding FPL's RFP process.

I
FPL's Responses To Objections Regarding RFP Minimum Requirements

The Minimum Requirements of FPL's RFP are set forth at pages 19 - 26 of FPL's RFP. Of the sixteen Minimum Requirements, seven have received some form of objection from PACE. FPL's responses follow.

A. Financial Viability or Minimum Debt Rating (PACE Objection C)

FPL has specified as a Minimum Requirement that for proposals supported by newly built generation, the Proposer or the guarantor of the Proposer "must possess a senior unsecured debt rating of not less than 'BBB' from Standard & Poor's or 'Baa2' from Moody's Investors Service with a 'stable' outlook." See RFP Section III E.5(a), page 21. PACE has objected to this requirement, alleging that it is "unfair, onerous, and unduly discriminatory." PACE Objections at 8.

PACE's position is based principally on the assertion that the requirement will eliminate many prospective Proposers from the field, "to the detriment of Florida [customers]" and "contrary to the purpose of the recent amendments to the Bid Rule." Id. 8-9. PACE's arguments in this regard are unavailing and are predicated in large measure on a misinterpretation (or a mischaracterization) of the RFP and the Financial Viability, or minimum debt rating, requirement.

An essential fact that PACE neglects to note is that the minimum debt rating requirement applies only to proposals involving the construction of new power plants. FPL is accepting bids from all entities proposing to meet the 2007 need by committing existing facilities, where the risks of financing and construction completion are no longer an issue. RFP Section III E (5), page 21. In fact, Calpine, Mirant, Reliant, El Paso, Progress Energy, and Constellation all have facilities in Florida with a combined total output of over 2604 MW. All of these entities willing to commit their existing units to FPL may submit proposals to supply power irrespective of their financial ratings.[3]

However, for Proposers who are planning to undertake the major investment of developing and constructing a power plant, FPL appropriately is insisting that they or their guarantors have an investment grade senior debt rating.[4] Rather than working "to the detriment" of FPL customers, the investment grade requirement for projects that carry financing and construction completion risk is necessary to protect FPL customers. Inviting entities with junk bond status to bid and potentially build a power plant whose timely and proper completion is

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[3] The senior debts of Calpine, Mirant, Reliant and El Paso all currently are rated below investment grade.

[4] PACE ignores the fact that where the Proposer itself does not meet the minimum debt rating, for purposes of a proposal it may enlist the support of a guarantor who does meet the requirement.

necessary to provide reliable, cost-effective electric service to FPL's customers is, at best, an unreasonable proposition and, at worst, a very poor bet with potentially serious detrimental consequences for Florida and its electric consumers.

Entities rated below BBB- have a historical five-year default rate of approximately 22%, substantially higher than the average default rate for higher rated entities.[5] Such entities have low investment ratings because they reflect high risks to their investors. That risk should stay with their investors. Those business risks should not be transferred to or shared with FPL's customers.

PACE is incorrect in asserting that other security requirements of the RFP, if left in place, lessen the need for a minimum debt rating. The Completion Security, though intended to protect customers in the event of default, cannot possibly contemplate all circumstances and potential for loss to FPL's customers. Further, as discussed more fully *infra* at 18, 19, the amount of Completion Security was based on several simplifying assumptions that are conservative and operate in favor of bidders. Additionally, there is no way to know for sure that replacement power will be available when needed. Taking on the financing and construction of a power plant requires financial strength and flexibility. Below-grade investment entities simply have too little of either for FPL to have sufficient confidence in a proposal from such an entity.

The minimum debt rating requirement minimizes the risk of having to deal with a bankrupt Proposer to meet the 2007 need. It helps avoid the associated detrimental consequences to customers. Indeed, should the Proposer go bankrupt, it may be expensive, time consuming or impossible to enforce the Completion Security or Step-In Right provisions in a bankruptcy court. Given the well-publicized recent supply contract rejections and/or attempted

[5] *Default and Recovery Rates of Corporate Bond Issuers,* Moody's Report, February 2003 (hereinafter "Moody's Report"). Exhibit 1 attached hereto.

renegotiations by bankrupt NRG and Mirant, and the fact that NEG turned six uncompleted plants over to its lender this summer,[6] the concern is clearly justified, and the RFP's Financial Viability standard is warranted. Simply stated, FPL is looking for greater certainty that the plant will be financed and built on time and in accordance with the terms of the PPA than would be presented by below-investment grade entities.

At the same time PACE advocates abandoning the minimum debt rating requirement because of other security arrangements and contract rights, it is urging the Commission to reduce significantly or eliminate these same security arrangements. PACE Objections, at pp. 9-11. As noted infra at 16, considering its objections as a whole, clearly PACE's intent is to have the Commission strip away the protective measures of the RFP to the point that a new developer, with no experience and no balance sheet strength, is trusted to timely and properly complete construction of a major power plant. PACE would have FPL and its customers rely almost wholly on "step-in" rights in the event of bankruptcy or non-performance, including where the Proposer simply makes an economic decision to abandon the project, as so many developers have done in recent times.

PACE uses Calpine as its "poster child" for the entity that will be excluded from participating in the RFP. As noted earlier, Calpine can submit proposals to supply power from its existing plants irrespective of its debt rating. Moreover, Calpine may submit a proposal to construct a power plant if it can support its proposal with a guaranty from an entity with investment grade senior debt. Nevertheless, if PACE would endeavor to convince this Commission that it is in the interest of FPL's customers to allow Calpine, absent such a guaranty,

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[6] Mirant Press Release, August 28, 2003; NEG Press Release, July 8, 2003; Southeast Power Report, October 14, 2002. *See* Exhibit 2 attached hereto.

to construct a power plant required to reliably and cost-effectively meet the 2007 need, there are a few things worth noting regarding Calpine's present circumstances and financial condition.

Within the last three months, Standard & Poor's (sometimes "S&P" hereafter) has downgraded Calpine's corporate credit rating three notches to "B" and Calpine's senior unsecured debt rating to "CCC+," citing the following significant risks facing the company:[7]

1. Calpine faces considerable liquidity issues through 2004 with $3.7 billion in potential refinancing and about $3.1 billion in capital expenditures.

2. Calpine has limited opportunities to reduce its debt burden and has taken on more debt to fund its construction program.

3. To meet its liquidity needs, Calpine must generate cash from sources other than operating cash flow. Calpine plans to meet these requirements through a combination of asset sales and debt financings which carry execution risk.

4. Calpine's target of 65% leverage to total capitalization makes the company vulnerable to electricity price volatility and to capital market access. Calpine's inability to access the equity markets has led to debt levels over 70%. Adjusted debt levels are expected to remain above 70% over the next five years.

The significant downgrades represent very large increases in Calpine's default risk according to Moody's. Companies with an issuer rating of "B" have a historical five year default rate of 32%, a ten year default rate of 50% and a twenty year default rate of 61%.[8] As of September 4, 2003, Calpine has 7,558 MW under construction.[9] Most, if not all of these projects were begun long before Calpine's recent three-notch downgrade by Standard & Poor's. According to S&P, Calpine must complete construction of the planned power plants or risk triggering an event of default at the Calpine corporate parent level. At best, the impact of Calpine undertaking a large project in response to FPL's RFP could only further stress Calpine's

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[7] Standard & Poor's, *Ratings Direct*, for Calpine Corp., June 2, 2003; Standard & Poor's, *Ratings Direct*, for Calpine Corp., August 28, 2003; *see* Exhibit 3 attached.

[8] Moody's Report, *supra note 5*.

[9] http://www.calpine.com/energy_assets_4/CPN_Portfolio.pdf.

balance sheet. Moreover, it is not clear whether or how Calpine could obtain the additional equity its lenders would require for such a project given Calpine's other commitments of capital over the next two years. Were FPL to enter into a purchased power agreement with Calpine that involved the construction of a new power plant, FPL and its customers would not be afforded the same level of comfort that Calpine's lenders are requiring and, in fact, would be competing against these other existing projects for allocation of capital funds.

PACE's contention that Calpine's bid was the low cost bid in the last RFP ignores critical facts. First, Calpine withdrew its bid following the date FPL submitted its testimony in which Mr. Moray Dewhurst indicated that a certain bidder "X" had been disqualified from further consideration in light of serious concerns regarding its financial viability. *See* Direct Testimony of Moray Dewhurst, July 16, 2002, Docket Nos. 020262-EI, 020263-EI, at pp. 11 – 13. It was later revealed that bidder "X" was Calpine. Docket Nos. 020262-EI, 020263-EI, Tr. 869. Second, even ignoring the impact of the equity adjustment, Calpine's proposal was not competitive in and of itself. Rather, it was the fortunate beneficiary of FPL's evaluation methodology having paired it with a proposal from El Paso that subsequently was determined to have been unrealistically priced and, arguably, under-priced[10] given El Paso's misunderstanding of certain key parameters of the RFP in formulating its proposal. Direct Testimony of Rene Silva, July 16, 2002, Docket Nos. 020262-EI, 020263-EI, at pp. 25-26, 31-35. It was El Paso, not Calpine, that made that portfolio appear to be competitive without an equity adjustment.

Contrary to PACE's assertion at page 8 of its Objections, the minimum debt rating criterion did exist in FPL's last RFP, albeit in a slightly different form. Although proposals were accepted from below-investment grade entities and evaluated, FPL's Supplemental RFP and

[10] The cost of the portfolio that included Calpine's proposal increased by approximately $28 million as a result of the necessary adjustments to El Paso's proposal.

FPL's management made it clear that FPL was not likely to execute a long-term PPA with an entity that was not investment grade, guaranteed by an investment grade parent or affiliate, or who otherwise demonstrated comparable financial strength or commitment to the project. *See* Supplemental RFP, Section IV. D., at 20. In fact, as noted above, proposals from investment grade entities with junk bond ratings were excluded from consideration for the short list. *See* Direct Testimony of Moray Dewhurst, July 16, 2002, Docket Nos. 020262-EI, 020263-EI, at pp. 11 – 13. No entity challenged the use or application of this financial viability screen prior to development of the short list. FPL has identified its minimum debt rating requirement in this RFP as a "minimum requirement" consistent with the terms of the revised Bid Rule. Because the criterion is reasonable and is designed to protect FPL customers, it makes sense to employ it earlier and avoid unnecessary analysis and evaluation. Currently, a number of the bidders in the last RFP are facing very serious, if not existence-challenging financial difficulties. Ignoring this heightened industry risk is inappropriate because it would not fairly consider the interests of FPL's customers.

PACE is careful not to state, but implies, that there are no other RFPs that contain minimum financial viability requirements. PACE Objections at 8. Although FPL has not conducted an extensive search of other RFPs (and apparently neither has PACE), FPL is aware of at least the following RFPs that require minimum credit ratings of respondents as a requirement to submit a proposal: Idaho Power Company Request For Proposals (issued March 14, 2003); North Carolina Municipal Power Agency Number 1 (issued July 21, 2003); Portland General Electric (issued June 18, 2003); Tennessee Valley Authority (issued January 16, 2001);

and Duke Power Request for Proposals (issued January 28, 2003) (the same RFP attached to PACE's Objections as Exhibit 4).[11]

The fact that TECO's recently issued RFP does not identify a minimum debt rating as a minimum requirement is hardly surprising given that the issuance is for a small amount of peaking capacity (between 50 MW and 225 MW), an amount that would not involve a plant subject to the Power Plant Siting Act and, therefore, the Bid Rule. Moreover, by the terms of its RFP, TECO left open for negotiation all questions regarding security and financial viability. While the Florida Power Corporation RFP, issued November 26, 2001, did not require that a bidder per se be investment grade, it did stipulate that "[s]ecurity must be guaranteed by entities that are investment grade." *"Request for Proposals for Power Supply Resources"* by Florida Power, November 26, 2001, p. III-3.

The construction of a power plant is a distinctly important decision in terms of assuring the continued delivery of reliable and cost-effective electric service to customers. In such an instance, the credit worthiness of Proposers must be seriously considered, in contrast to other instances involving smaller or less critical transactions where completion and performance security provisions alone might provide a sufficient level of protection and a minimum investment grade rating may not be warranted. The credit rating level chosen by FPL was the maximum level of risk to which FPL felt its customers should be exposed for an undertaking as significant as the financing and construction of a power plant. FPL declines to expose its customers to an unreasonable level of risk associated with the financing and construction of a power plant by an entity with junk bond status. The liquidated damages and other remedies

[11] See attached Exhibit 4, which contains relevant pages.

secured by the Completion and Performance Security requirements, although providing important protections, will not in and of themselves ensure that the lights remain on.

B. Completion and Performance Security Requirements (PACE Objection D)

FPL has required entities submitting proposals based on the construction of new generation to accept a Completion Security requirement of $188,000 per MW. See RFP Section III E.5)a), page 21, RFP Section II.H., pages 15-16. FPL also has required all Proposers to accept a Performance Security requirement of $95,000 per MW. See RFP Section III E.5)b), page 21, RFP Section II.H., pages 15-16.

PACE has objected to these minimum requirements, alleging that they are "unfair, unduly discriminatory, and onerous." PACE Objections at 10. PACE's position is based on two principal assertions: 1) an alleged lack of comparability requirements in other RFPs; and 2) that FPL "imposes no similar risk on its self-build proposal that would protect consumers from any [completion or performance failures]." See PACE Objections at 10-11.

PACE's arguments in this regard are unavailing. They misinterpret relevant provisions of the RFP, and they misapprehend fundamental distinctions between the unregulated environment in which an IPP's project would be constructed and/or operated and the regulated environment in which FPL's self-build option would be constructed and operated. They also fail to acknowledge the present financial woes of the independent power industry and the associated risks to FPL's customers of entering into a long-term purchased power agreement with a financially questionable entity.

PACE's assertion that the requirements are "restrictive and punitive....regarding the form and substance of the security that must be posted" (PACE Objections at 10) is premised on a complete misreading of the RFP. The "offending" provision at page 16 of the RFP referred to by PACE states in pertinent part:

> A minimum of 10% of the Completion Security and Performance Security must be provided in the form of cash in U.S. Dollars, U.S. Governmental Bonds deposited with an Issuer acceptable to FPL, **OR** an irrevocable standby Letter of credit (LOC) drawn on an Issuer acceptable to FPL. Remaining security requirements may be provided with a combination of cash, Letter Of Credit (LOC) **OR** a company guarantee based on the Proposer's credit quality and tangible net worth.

(Emphasis added). Thus, contrary to PACE's contentions, clearly an entity is not required to post at least ten percent of the security in cash, and is not required to post the remainder of the security through a letter of credit.[12]

PACE's position regarding the Completion and Performance Security intentionally ignores essential differences between the respective regulatory regimes in which an IPP plant and FPL's self-build option would be constructed and operated. A public utility is cost-of-service regulated and has an obligation to provide reliable, cost effective electric service to all customers. An IPP has the ability to sell power at market-based rates; its service is unregulated as to reliability; and it has no "obligation to serve."

Since an entity selling power to FPL might well not be subject to Commission regulatory oversight, one of FPL's primary considerations in drafting the sample Purchased Power Agreement ("PPA") attached to the RFP was protection of FPL's customers in the event of the supplier's failure to perform. Customers are protected from FPL's failure to perform by the Commission. However, entities that sign contracts to provide purchased power to FPL as a

[12] PACE's misreading of a provision so important to its members that it warranted the accusation that the provision is "restrictive and punitive" is indicative of the overall nature and thrust of PACE's objections. It is an exercise in "mud-slinging," the purpose of which is to cast as many aspersions as possible on FPL and its RFP.

result of an RFP are not subject to Commission regulation and oversight as to that wholesale activity. So, for customers to be protected, they must be protected by the terms of the contract, or not at all.

Only through specific provisions in the PPA can FPL ensure that an unregulated supplier will do "whatever it takes" to deliver on schedule and as proposed, such that FPL can fulfill its obligation to provide reliable, cost-effective electric service to customers. Contract commitments alone are not sufficient to protect the customer. There must be sufficient amounts of cash on hand to pay for replacement capacity and energy, on short notice, in what could be tight supply conditions. And in order for these contract provisions to have practical value and meaningful consequences, appropriate security amounts must be required of unregulated suppliers. That is the purpose of the Completion Security and the Performance Security.

At its essence, PACE's argument that Proposers should not be held to completion and performance standards that are not identical to standards pursuant to which a public utility is regulated is an ill-concealed attempt to shift risks away from itself and its investors and onto FPL and its customers, without assuming the corresponding cost-of-service and reliability regulation. For example, if the utility builds a plant at a cost below that which was projected or operates the plant at performance levels better than were estimated, customers capture that benefit. Conversely, if an IPP builds a plant at a lower cost than projected or operates better than planned, its shareholders capture that benefit. The IPP must accept the risks, costs, and obligations of operating as an IPP along with the benefits.

Step-in rights alone, contrary to PACE's contention, are insufficient to protect customers.[13] Throughout its objections, PACE has either ignored or failed to recognize how the

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[13] It is noteworthy that in arguing against the minimum financial rating requirements,

three functions of Financial Viability (minimum debt rating), Completion and Performance Security provisions and Step-In Rights work in a balanced, non-redundant fashion to protect customers. The Completion and Performance Security provisions provide guarantees and cash equivalents to compensate our customers for damages resulting from lack of completion and/or performance by the developer. These requirements also provide meaningful incentives for the Proposer to perform under the PPA as promised. Failing adequacy of the Completion and Performance Security, e.g., where money damages alone are not sufficient to ensure that the lights will remain on, Step-In Rights give FPL the right to protect customers by performing work that the Proposer is unable or unwilling to do. As discussed, *supra* at 7-11, the Financial Viability requirement, or minimum debt rating, is necessary to minimize the risk of bankruptcy by a Proposer, an event that carries its own set of costs and consequences for the purchasing utility and its customers which may only be partially, if at all, addressed by the other security requirements and Step-In Rights.

What PACE wishes to see is a new developer, with no experience and no balance sheet strength, be awarded the bid based upon a promised low price and without having to post security. If the developer is unable to meet any of the project Milestones, FPL's customers' sole protection would be for FPL to "Step In." If FPL were to exercise its Step-In Rights under Section 5.1.1 of the draft PPA, FPL would be paid its costs by the developer (Section 5.1.3) (a payment obligation itself secured by the Completion Security and the Performance Security), but the developer would still be paid its Capacity and Energy Payments (Section 5.1.2). In essence, the proposed Step-In Rights alone, without other meaningful security requirements, are

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PACE asserts that a combination of completion and performance security, and step-in rights are sufficient to protect customers. Now, when arguing against the Completion and Performance Security, PACE contends that step-in rights should be sufficient "to remedy completion and performance concerns." PACE Objections at 11.

tantamount to an invitation for a financially strapped developer to arbitrage the difference between its costs and capabilities versus FPL's. This would provide the developer the option of using FPL's personnel, skills, experience and financial strength to support its profits.

In short, the provisions cited protect FPL's customers by 1) making sure there are funds available to compensate them for extra costs caused by the Proposer's failure to meet its promises (Security provisions), 2) assuring them that FPL will see that the plant is completed and operated as promised (Step-In Rights), and 3) reducing the risk of the developer going bankrupt after FPL and its customers agree to rely upon the developer's commitment (Financial Viability).

Without foundation or support, PACE summarily concludes that the levels of required Completion and Performance Security are excessive. As described in detail below, the levels of Completion and Performance Security were reasonably and responsibly derived and provide appropriate protection for FPL's customers given the current and foreseeable environment. The Completion Security protects customers from the failure of a Proposer to make timely delivery of the capacity and energy it has contracted to deliver and the associated loss of reliability and increased costs. The Completion Security protects customers in two distinct ways. First, it provides a significant financial motivation for the Proposer to finish its project on time and avoid forfeiture of the Completion Security. Second, in the event the Proposer fails to perform, then the Completion Security provides a significant source of funds for FPL to be able to replace the undelivered capacity and energy without customers having to pay higher prices.

In formulating the Completion Security amount, FPL took a conservative approach, attempting to balance the need to protect customers with the financial impact of a security provision on a Proposer. FPL captured in the Completion Security calculation the incremental costs customers would face if FPL had to replace the energy and the capacity to be supplied by the Proposer. It was assumed that FPL would purchase capacity necessary to meet its 20% reserve margin requirement for two years at $5/kW per month (potentially a very optimistic price) until FPL could bring 4 CTs into service. The calculation also assumed that FPL would continue to purchase capacity equal to the difference between its 1066 MW need and the amount of capacity available from the 4 CTs until FPL could convert the 4 CTs into a 4x1 combined cycle ("CC") unit.[14] From the cost of this expedited and phased CC construction, FPL netted capacity costs it would not have to pay the Proposers. It then added to this incremental cost its estimated replacement energy costs over the four-year period. In making that calculation, FPL made a simplifying, but very conservative assumption that the 4 CTs would not have to be removed from service to convert them from simple cycle to combined cycle mode. The total incremental cost was calculated and then divided by the total MWs of need to obtain a per MW value. Accordingly, the amount of the Completion Security required varies depending upon the MW of firm capacity a Proposer proposes and, thus is a ratable requirement.

Although the amount of the Completion Security on a per MW basis is larger than the amount of the Completion Security required in FPL's last RFP,[15] the $188,000 per MW value was calculated on a more rigorous basis than the prior requirement. Essentially, FPL concluded that the Completion Security required in the last RFP did not provide sufficient protection for FPL's customers. FPL never represented that the amount of Completion Security required in the last RFP would have been sufficient to protect customers in all circumstances. Similarly FPL does not represent that the amount of Completion Security required in connection with this RFP

[14] The analysis covered a four year period: two years of purchased power, and two years with the CTs in service.

[15] In this RFP FPL is requiring a Completion Security of $188,000 per MW. In FPL's 2002 RFP, it required a Completion Security of $50,000 per MW.

will protect customers in all circumstances. However, FPL believes that it provides a reasonable amount of protection for its customers.

To mitigate the impact of this security requirement on Proposers, FPL not only performed the security calculation conservatively, but also allowed more credit-worthy Proposers a line of credit that reduced the amount of cash or equivalent that had to be posted. In fact, the security requirements in this RFP arguably are more favorable to above-investment grade entities than were the requirements in the last RFP. Actual liquid security (in the form of cash/letter of credit ("LOC")) to be provided by an investment grade entity with adequate net worth will be lower under this RFP (10% of Completion Security which equates to less than $20,000 per MW vs. $50,000 per MW in last RFP). Further, the remaining amount of required completion security may be provided with a corporate guarantee at no out-of-pocket cost to the bidder.

Lenders must necessarily assess risk, including potential performance risk, when providing financing for projects. If the risk of nonperformance is as minimal as potential Proposers have suggested to the Commission, then having to post Completion Security to protect against this minimal risk should not foreclose financing of projects. If the posting of this Completion Security makes a project non-financeable, it is either because the completion risk is so great or the Proposer is so financially risky that the addition of this completion risk makes them too risky to finance. Customers need to be protected from both risks, and the Completion Security provision prevents shifting these risks to customers.

The Completion Security requirements are financeable for an investment grade entity with adequate net worth. These Proposers would be required to provide only 10% of the Completion Security requirements in the form of a LOC, treasury bills, or cash. This would amount to less than $20 million if the entire need was satisfied and should be able to be secured at a reasonable cost, certainly within reach of any investment grade entity.[16] The remaining security may be provided with a company or parent/affiliate guarantee. If a proposal proves to be non-financeable, it will be because an entity has insufficient credit ratings and/or net worth, but not because the Completion Security requirements are onerous.

Likewise, the Performance Security required in this RFP has been reasonably and rationally derived and represents the amount and form of security FPL believes is necessary to adequately protect customers. The Performance Security provision in the RFP and the PPA was included to protect customers from a developer failing to perform as it contracts. This failure to perform could manifest in a number of forms: failure to provide the contracted MW, failure to achieve the contracted heat rate, or failure to achieve contracted availability. In each instance the result is that FPL will incur replacement power costs that it will attempt to pass to its customers.

The Commission oversees the performance of FPL's units on a regular basis and has a regular proceeding in which it reviews not only fuel and purchased power costs but also generating unit performance. It has developed an incentive mechanism that rewards extraordinary performance and penalizes poor performance. There is no regulatory mechanism in place to protect FPL customers from poor performance by a Proposer pursuant to its PPA. So, if customers are to be protected, they need protection through the provisions of the PPA contract. That is the purpose of the Performance Security provision in the PPA.

The risk of less-than-contracted performance extends over the life of the PPA, which could be as much as 25 years. Rather than require Proposers to post a security that would cover the potential damages for poor performance for the life of the contract, FPL determined that one half of the Completion Security, which envisioned essentially a four-year computation of

[16] Based on current market conditions, FPL's annual cost for LOC's is approximately 60 to 75 basis points.

damages, would be a reasonable Performance Security balance. Once again, this is a conservative approach, as it is entirely conceivable that a Proposer could have poor performance for more than two years.

Similar to the requirements for Completion Security, for creditworthy entities with sufficient net worth, only 10% of Performance Security will be required in a liquid form (cash/LOC). The remainder may be provided in the form of a corporate guarantee, at no out-of-pocket cost to the bidder. So, there should be no reasonable concern that the required Performance Security will make a financially viable project non-financeable. Again, if a proposal proves to be non-financeable, it will be because an entity has insufficient credit ratings and/or net worth, but not because the Performance Security requirements are onerous.

FPL did not include a Performance Security as a Minimum Requirement in its last RFP, but Performance Security requirements were included in the draft of the PPA provided to the short-listed bidder. The amount of Performance Security was left open and was to be negotiated as part of the PPA document. So, the absence of such a performance security provision as a Minimum Requirement in FPL's last RFP should not be read as an indication that FPL did not feel such security was necessary or appropriate. By making it a Minimum Requirement in this RFP, FPL is fully disclosing its importance and amount and giving notice that it hopes to attract only developers that can perform.

Taken together, FPL's Completion and Performance Security provisions adequately protect customers from completion and performance risks associated with purchasing power. They are conservatively calculated, and FPL has balanced the interest of Proposers by allowing the more credit-worthy developers to post reduced levels of cash. These security requirements may adversely affect the ability of a limited amount of less financially viable Proposers from being able to finance, but if it does, it is only because of their fundamental risk profiles, and it protects FPL's customers if such Proposers with unacceptable risks are discouraged from submitting proposals.

For years the Commission has heard from potential Proposers just how successful they have been in constructing plants and how reliable and dependable their plants will be, and that adding such plants would enhance reliability of service and lower costs. If these plants turn out to be as advertised, then there will be little or no damages payable to the developer under either the Completion or Performance Security. However, if there is a significant failure to perform, the Completion and Performance Security will be in place to protect customers for the failure to perform.

PACE alleges that the level of Completion and Performance Security are excessive relative to other RFPs. PACE fails either to comprehend or acknowledge that many RFPs and PPAs have security requirements that are based on the actual cost of replacement power (i.e., they contain mark-to-market provisions whereby additional security must be posted to cover replacement cost each time the market moves).[17] These types of requirements are inherently more uncertain and potentially larger than the security requirements in FPL's RFP. In addition, FPL can point to at least three cases where the Performance Security set forth in the RFP or PPA is equal to or greater than FPL's Performance Security.[18]

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[17] See, Duke Power Request for Proposals, Model Power Sales Agreement, Appendix A (issued January 28, 2003), at 1-5; Entergy Services, Inc. Request for Proposals, Appendix G (issued April 18, 2003), at G-22–G-24, copies of relevant pages of which are attached as Exhibit 5.

[18] See, Cheyenne Light, Fuel and Power Company, Request for Proposals (Issued December 2002), p.13 ($117,000 - 151,000/MW); Northern States Model Purchase Agreement, at 34 ($100,000/MW); and Public Service of Colorado Request for Proposals and PPA, (issued January 28, 2000), at 32, copies of relevant pages of which are attached as Exhibit 6.

However, the proper test of whether the level of Completion or Performance Security is fair is not what has been required in California, Idaho, North Carolina or Maine. The proper test is whether the security levels adequately protect FPL's customers. To make that assessment, one must estimate likely costs customers will be asked to incur due to the absence of completion or performance.

FPL has explained the approaches it took in determining the amounts of costs it felt was at risk due to lack of completion or performance. In performing those calculations, FPL used some very conservative assumptions that benefited Proposers. FPL then significantly mitigated the impact of these security requirements by limiting the amounts of liquid assets that had to be pledged by credit-worthy Proposers. This approach does not protect FPL's customers from every conceivable risk or even the largest amount of potential costs they may be asked to pay for a Proposers' failure to perform, but it does provide a reasonable amount of protection.

With the benefit of hindsight, FPL acknowledges that in its last RFP FPL required too little security. Given the events of the intervening months, including the significant number of IPP projects abandoned or turned over to creditors, FPL is unwilling to subject its customers to the risks of requiring too little security. Absent adequate amounts of a Completion and Performance security, there is no certain mechanism that would enable FPL or the Commission to protect the customer.

C. Minimum Experience of Proposers (PACE Objection N)

FPL has required that all Proposers with proposals supported by new construction "must have successfully executed the development, permitting, design, procurement, construction and commissioning of a project similar to that proposed" and that "the operating entity must have over five years of demonstrated experience in the successful and reliable operation of facilities employing the technology similar to that proposed." See RFP Section III E.10), page 23.

PACE objects to the RFP's minimum experience requirements as onerous, principally focusing on what it misperceives as a requirement that the Proposer itself have five years of demonstrated experience. This misperception leads PACE to discuss IOU subsidiaries that have been formed to compete in unregulated wholesale markets, where the parent organization has much more than five years of such experience but the newly formed subsidiary does not. As an example, PACE cites Southern Company's Mirant Energy subsidiary.

PACE's misperception renders its principal argument essentially moot. The only requirement in the RFP that must be met by the Proposer itself is to have successfully developed, permitted and built a single project similar to the one it is proposing to FPL. Surely FPL cannot be faulted for wanting to protect itself and its customers from Proposers who have no relevant power plant experience whatsoever. Contrary to PACE's misperception, the RFP does *not* require that the Proposer have five years of operational experience; rather, this requirement applies to the "operating entity," which can be the Proposer or any other entity that the Proposer engages to operate its facility. There are a number of experienced power plant operators who can be commercially retained to operate a facility and who would thus meet the RFP's five-year experience requirement.

PACE's use of Mirant Energy as an example of a newly-formed subsidiary that should be entrusted with responsibility to supply reliable power is curious, in view of recent developments. Mirant is presently in Chapter 11 bankruptcy proceedings and is presently trying to reject or renegotiate various agreements to purchase and sell power. This hardly seems emblematic of the dependable performance that FPL is properly seeking.

PACE also suggests that FPL's minimum experience requirements is somehow improper because there was no counterpart in FPL's last RFP. This is hardly impropriety; it is simply learning from one's mistakes. One of the Proposers in FPL's last RFP, which has contested the results of that RFP vigorously, was found through discovery to have virtually no experience and no prospects for successfully building and operating a power plant. FPL had frankly not anticipated that it would need to guard against utterly inexperienced Proposers, but now knows better and is protecting itself and its customers accordingly from all such entities.

It is not unusual within the industry to require Proposers to have appropriate experience. For example, the May 30, 2003, RFP by the Long Island Power Authority (LIPA) includes a requirement that:

> The Respondent must also have demonstrable experience and expertise in the areas of power plant and/or transmission development, financing, permitting, siting, construction and operation.

(Request for Proposals to Provide Capacity, Energy & Ancillary Services to the Long Island Power Authority, Section III, p. 3). While LIPA's RFP takes an open-ended approach to specifying the required experience, FPL believes that its "pass/fail" experience criteria are preferable to protect the Proposer's interests as well as its own. Under the FPL approach, there is no discretionary evaluation of the Proposer's experience level, which can become a source of dispute. Rather, FPL has set simple, readily ascertainable criteria: a bright line test. An inexperienced potential Proposer who does not meet those criteria need not waste its time, effort and money by submitting a proposal that will be rejected later, once its lack of experience is considered.

D. Site Development (PACE Remedy in Objection A)

FPL has required Proposers with proposals based on new generation to be responsible for the location, development and permitting of its proposed site. FPL has not permitted co-location at its Turkey Point site where its next planned generating unit would be located (or at any other FPL site). See RFP Section III E.12), page 24. This minimum term has not been objected to by PACE, but PACE does include a sentence in its Objections that the Commission should direct that the Turkey Point site be made available to Proposers. See PACE Objections at 6.

Co-location of another entity's power plant at an FPL site presents a host of difficult issues, including, but not limited to: liability and risk management, site control and security, sharing of common areas and facilities, uneconomic duplication of facilities or personnel and more difficult contract negotiation and administration. These serious considerations for any plant site are compounded by the fact that the Turkey Point site contains nuclear units subject to a host of special regulatory requirements. Given these challenges, co-location is not a practical alternative at the Turkey Point site.

In its effort to serve its customers effectively, FPL has developed and implemented processes for the construction, operation and maintenance of its generating units that have resulted in FPL achieving the highest levels of safety, reliability and availability, combined with the lowest construction and operation and maintenance costs in the industry. In part, these processes depend on FPL having full control of activities at its plant sites.

When FPL builds a new unit at an existing site, it assigns responsibility for the future performance of the new unit to the management team of the existing units. In this manner, the future success of the new unit is as important to the plant management team as is the continuing successful performance of the existing units. This results in optimal resolution of issues caused by differences in the objectives of the operation and maintenance of existing units and those of the unit under construction. This internal cooperation is reflected in FPL's success.

If a different entity, not under FPL control, were to construct a new unit on FPL's plant, this effective synergy would be lost. The construction entity would be trying to optimize its efforts focusing exclusively on what would make the new unit successful. If construction were conducted on a greenfield site, this approach would be correct. But at a site with existing operating units, this would create conflicts. FPL would not be willing to subordinate the objectives of its existing units to those of another entity building a new unit, and the entity building the new unit would not want to accept constraints regarding its construction process. These conflicts could lead to disagreements as to who is responsible for delays, cost increases, sub-par-performance, etc. None of this is in the best interest of FPL's customers.

Co-location also raises difficult issues of environmental compliance. How would point source discharge or air emissions be measured and reported? Would FPL be responsible for emissions or discharges from its site for activities associated with activities attributable to its tenant? Could FPL find itself the subject of enforcement actions due to activities of its tenant?

Co-location could also adversely affect efficient operation and maintenance ("O&M") of FPL units. FPL optimizes the operation of units within a site to control O & M costs and keep its rates low. This optimization consists, among other practices, of sharing some of the manpower from the earlier unit(s) to operate and maintain the new units. This leveraging of employees results in a reduction in the number of employees/MW and reduces the cost of O & M in \$/MW. Another example is the utilization by the new unit of existing control facilities. FPL's sites have limited remaining space for future addition. To the extent that some or all of the remaining space is used by a different entity, the opportunities for FPL to increase the benefits of optimizing operations at a site are diminished.

Yet another problem arises with the potential loss of a site for the benefit of FPL customers when a PPA expires but the site is still occupied by an entity that has no obligation, contractual or otherwise, to serve FPL customers. FPL would not be able to reclaim the site for the location of another generating facility to serve FPL customers.

In addition, FPL remains opposed to any attempt to force it to make its limited power plant sites available to other entities. FPL has constitutionally protected interests in its property which it remains prepared to defend.

In its last RFP, FPL included an identical site development requirement. No developer took an exception, and this was not challenged in the ensuing need case. Moreover, in the subsequent Bid Rule amendment proceeding, the Commission declined to adopt a rule revision requiring consideration of co-location, despite having explicitly considered such language. In fact, PACE, which now advocates co-location, explicitly withdrew its advocacy of co-location in those proceedings. Given the Commission's decision not to include co-location language in the Bid Rule, it cannot be reasonably argued that FPL's decision not to entertain co-location in its RFP violates the Bid Rule. Consequently, there is no basis to direct FPL to make its Turkey Point site available for co-location to potential Proposers.

E. Project Site Certification Schedule (PACE Objection E)

FPL has required that Proposers with proposals based on new generation agree to file a Site Certification application on or before April 1, 2004. See RFP Section III E.13, page 24. FPL retains the right to terminate negotiations if a Proposer fails to meet the April 1, 2004, date.

PACE has objected to this milestone for filing the site certification application on essentially two grounds. First, it argues that it is unrealistic to require Proposers to meet this milestone because the process to prepare an application would need to have started in July 2003. As such, PACE argues that those who do not have a suitable site and have not already begun the process to prepare an application would not be able to demonstrate the ability to meet the milestone. Second, PACE argues that it is commercially infeasible, onerous and unfair for FPL to require Proposers to file a Site Certification application before contract negotiations have been concluded. PACE argues that Proposers should not have to expend money to prepare a site application prior to being declared the "winner" of the RFP. Neither of these is a valid objection, because they ignore the realities of siting and constructing a major power plant project.

FPL requires that the site certification application be filed by April 1, 2004, not to add to the Proposers' burden, but simply because it knows that if this date is not met, a project cannot meet the required in-service date of June 1, 2007. Thus, PACE's objections are essentially an attack on the June 1, 2007, in-service date. But that in-service date is essential if a project is going to be available to meet the need it is intended to serve. Any serious Proposer has been fully aware of FPL's capacity requirements in 2007, because they are set out in the Ten-Year Site Plan filing that FPL made in April 2003. Moreover, information on the concerns associated with the load and generation imbalance for Southeast Florida was made available by FPL as early as November 2002 by posting that information on FPL's OASIS website. Again, any serious Proposer would be aware of information on this website. And FPL is not singling out Proposers for the April 1, 2004, deadline. If FPL is to preserve its self-build option of Turkey Point 5, it too will have to file its site certification application before that date.

There is no merit to the argument that Proposers would have needed to begin the site certification process in July 2003 to meet the April 1, 2004, deadline. Any Proposer with experience with the Power Plant Siting Act and the licensing of new facilities would know that if they have a suitable site, there is more than enough time left to start today and still prepare and submit a Site Certification application by April 1, 2004.

Finally, PACE's complaint that Proposers will have to expend funds preparing for site certification before they know whether their project will be selected is either naive or disingenuous. Bidding to supply a major project such as a power plant necessarily entails a substantial commitment of resources up front, with no certainty that they will be recovered. This risk is routinely handled by pricing the proposed project such that the return on investment if it is selected compensates for the risk.

To follow PACE's argument to an absurd conclusion, Proposers would not start spending capital until the conclusion of negotiations. Then, following their argument that it would take 9 months to prepare the application, it would not be filed until late 2004 or early 2005. Given the statutory times set in the PPSA and the time needed for construction, this would result in the project missing its necessary start date by six months to a year, even if there were no other unforeseen delays.

It is important to provide some sort of incentive for the Proposer to meet the milestone for site certification. Proposers who seriously want to be the successful bidder in this process and meet the needs of FPL's customers are going to aggressively pursue the preparation and filing of a Site Certification application and spend money in advance of the final negotiations just as FPL will have to do. If this milestone cannot be met, then the project will not meet its in-service date, and the sooner FPL is aware of a delivery problem, the sooner it can act to mitigate the cost impact on its customers. This site-certification milestone is typical of PPA contracts based on new generation and is justified as a protection of FPL customers from potential late delivery.

F. The RFP's Dual Fuel Requirement (PACE Objection J)

FPL has required that all newly built gas-fired generation proposals include the capability to operate on distillate (#2) fuel oil as a secondary fuel to satisfy reliability and continuity concerns. See RFP Section III E.11), page 24.

PACE objects to the RFP's dual fuel capability requirement as onerous and unreasonable with respect to proposals that would be located where natural gas from both the FGT and Gulfstream pipelines is available. As evidence that capability to burn distillate oil is unnecessary in such locations, PACE asserts that FPL has recently added significant generation capacity at the Martin and Manatee plants as natural gas-only facilities.

PACE is only partly correct in its assertion about the Martin and Manatee additions. Contrary to PACE's assertion, Martin Unit 8 will have the necessary facilities to burn distillate oil, but PACE is correct that FPL does not plan to have that capability at Manatee Unit 3.[19] As discussed in the testimony of FPL witness Gerard Yupp in FPL's last need determination proceeding, FPL decided that distillate oil capability was unnecessary for Manatee Unit 3 because the Manatee plant is situated where it has excellent access to both the FGT and Gulfstream pipelines. Moreover, FPL will have firm transportation contracts on both pipelines greater than the capacity of Manatee and can arrange to "detour" gas to the Manatee plant in the

[19] PACE also appears misinformed as to the rationale for adding dual fuel capability to the proposed Turkey Point self-build unit. This capability has not been added because of the limited gas supply to Dade County. In fact, any gas fired power plant addition to the area will require increased gas capability through upgrades to the gas transmission line, and such upgrades are included in the proposed self build unit. The distillate oil firing capability is provided in addition to this reinforcement of the gas supply.

event that the other pipeline were temporarily unavailable. Because of this flexibility, FPL decided that it had the effective equivalent of dual fuel capability for Manatee Unit 3 in the sense that it had two independent and reliable sources of gas supply.

After reviewing the purpose served by the RFP's dual fuel capability requirement, FPL has decided that it will accept and evaluate proposals that do not have distillate oil capability if they have two, independent and reliable sources of gas supply. FPL cautions, however, that any Proposer who intends to rely upon multiple gas supplies to meet the dual fuel capability requirement must provide sufficient detail to demonstrate that the supplies are indeed independent and that the Proposer has the physical, logistical and contractual ability to rely upon both supplies at all times that they might be required. This demonstration would include, but not be limited to, an affirmation by the Proposer that the Proposer has or shall obtain firm gas transportation capability for both sources of supply, each sufficient to meet the proposed facility's fuel needs. FPL's economic analysis of a proposal will assume that if a proposed new unit does not have distillate oil capability, it will have firm gas transportation capability on two independent transportation systems and that the Proposer will charge FPL for the cost of reserving capacity on both of those transportation systems unless the Proposer expressly affirms otherwise.

G. The RFP Evaluation Fee (PACE Objection M)

PACE attacks the RFP's $10,000 fee per proposal as "unfair, onerous, and unduly discriminatory." It offers three supporting arguments: (1) The RFP evaluation fee is not cost-based;" (2) Although PACE does not presently contest the $10,000 proposal fee for evaluation on "an initial Proposal", PACE seeks to have FPL allow "at least two variations to the original proposal without imposing on the bidder the requirement to pay another $10,000 evaluation fee."

PACE argues that the approach used in an FPC RFP (essentially allowing evaluation of a proposal and two variations of that proposal for a $10,000 fee and a $1,000 evaluation fee for any additional variations) should be a requirement placed upon FPL; and (3) FPL should not be allowed to keep 25% of an application fee if it finds that the proposal is non-responsive or ineligible.

The statement that FPL's RFP evaluation fee is "not cost-based" is simply incorrect. In deriving the RFP evaluation fee amount of $10,000, FPL first totaled the major incremental costs that were incurred for FPL's most recent RFP (the Supplemental RFP). This total did not include salaries, overtime, time that could have been spent on other work, or travel costs related to the RFP for FPL personnel. This was the cost of outside consultants and attorneys, computer software and notices necessary to develop and administer the RFP. This total of incremental costs was then divided by the total number of eligible bids (bids that received detailed economic evaluation). The resulting quotient of incremental cost per eligible proposal was approximately $9,600 in 2002 dollars. Consequently, FPL judged that a 2003 cost per proposal of $10,000 was both cost-based (incremental) and reasonable. (If internal FPL resources devoted to the RFP had been included, the cost would have been much higher.)

In regard to the second assertion by PACE that a Proposer should be allowed more than one proposal (or as PACE calls it, one or more "variations" of an initial proposal) for no cost or reduced cost, FPL considered that approach for the 2003 RFP. Ultimately, FPL rejected such a "buy one, get one (or two) free" approach for several reasons.

First, FPL utilized a similar approach in its recently concluded RFP effort in which certain variations to a proposal were evaluated for no additional fee. When FPL derived the $10,000 RFP evaluation fee discussed above, each of these variations were included as FPL counted up the number of proposals that served as the denominator in the cost-per-proposal calculation. If FPL had removed these variations from the denominator and had used only one proposal per Proposer in the calculation, the resulting RFP evaluation fee would have been in excess of $20,000 per proposal. In that case, allowing another "variation" for no additional cost would still have resulted in a "per proposal fee" of $10,000.

Second, FPL's experience in its recently concluded RFP effort shows that the economic evaluation work of analyzing RFP proposals constitutes the bulk of the evaluation time and effort. In the economic evaluation, there is essentially no difference in the amount of time and work required to evaluate one proposal and one "variation" of this proposal from Proposer A or to evaluate one proposal each from Proposer B and Proposer C. In either case, the evaluation is looking at two distinct proposals, and the computing time is substantially the same. Therefore, it is logical and fair to charge Proposer A the same evaluation fee for evaluating both its "original proposal" and its "variation" as it would charge Proposer B and Proposer C for the single proposal that each submitted.

Third, FPL's experience in its recently concluded RFP effort in which it allowed certain variations to be evaluated at no additional cost led FPL to conclude that this approach showed no clear benefits in terms of FPL receiving "better" capacity options to choose from. PACE's example of allowing a variation that results in "changing the proposal from 10 years to 11 years" is representative of many of the variations the FPL saw in its recent RFP work. This "shotgun" type of approach often results in two proposals that emerge from the economic evaluation without significant differences between them, but which take up an identical amount of time and effort in this evaluation. Consequently, FPL believes it is to its customers' advantage to encourage Proposers to expend effort in further refining what they believe their strongest proposal is, rather than being diverted by trying to develop similar "variations" that require additional evaluation time and effort.

In regard to PACE's objection to the RFP's language about keeping 25% of the evaluation fee for proposals that are deemed non-responsive or ineligible, PACE attempts to illustrate this with an extreme example and disregards what has been FPL's practice in this regard in its most recent RFP experience. PACE's example states that if a bidder submitted 5 proposals but did not have an Officer certify these proposals, then FPL would deem all 5 proposals as ineligible and would then keep $2,500 from each of the five $10,000 evaluation fees. While such an omission is possible from a Proposer, FPL's practice in its RFP efforts has been to contact the Proposer, point out the omission, and request that it be corrected. FPL did that repeatedly in its last RFP work. Furthermore, the RFP states on page 19 that FPL reserves the right to waive inconsequential non-compliance with the Minimum Requirements of the RFP. Clearly, both FPL's practice and the language in the current RFP indicate that FPL is allowing room for flexibility in dealing with omissions or other issues that would otherwise lead a proposal to be deemed ineligible.

Nevertheless, in FPL's recently concluded RFP efforts, there were some Proposers whom FPL had to "chase" repeatedly in an effort to clear up problem areas. In a few of these cases, these problems were not cleared up and the proposals were declared ineligible. In those cases, FPL returned both the proposals and the full evaluation fees.

In preparing the 2003 RFP, FPL concluded that this practice of returning problem proposals and the full evaluation fee was counterproductive, since the time it takes to repeatedly chase such Proposers reduces the available evaluation time. FPL seeks to minimize or eliminate such occurrences in this RFP and believes that the knowledge that FPL will be able to retain 25%

of the evaluation fee will result in not only more complete proposals being received, but also more cooperation in regard to clarification/omission requests that FPL might subsequently make.

In summary, the evaluation fee aspect of FPL's 2003 RFP is cost-based and reasonable. The fee is designed to result in FPL receiving the best capacity option proposals available with all required information included in those proposals.

H. Regulatory Modifications Provision (PACE Objection B)

FPL has included, as a Minimum Requirement of its RFP, acceptance by a Proposer or "would be seller" of FPL's Regulatory Modifications Provision. This provision, sometimes referred to as a "regulatory out" provision, passes any disallowance regarding recovery of costs under the PPA from FPL to the seller. This provision also gives the seller (not FPL) the option to terminate the contract in the event that FPL reduces the amount of a payment, consistent with a disallowance. Furthermore, this provision requires FPL to defend the validity of the contract and its right to recover from its customers all payments required under the contract, as well as cooperate with the seller in any proceeding to recover such costs. See RFP Section III E.15), pages 25-6. PACE has objected to this minimum requirement on the grounds that it imposes regulatory risks solely on sellers and that, in PACE's opinion, it is unfair, onerous, unduly discriminatory and commercially infeasible.

In its objection, PACE states that the Regulatory Modifications Provisions "likely will render projects unable to obtain long-term project financing." In fact, this provision would not necessarily make a project non-financeable. Any strong, financially viable entity can secure financing for projects supported by a contract that contains this provision, particularly given the small risk of disallowance by the Florida Public Service Commission, a sophisticated regulatory agency perceived by the investment community as reasonable, which has no history of disallowing recovery of costs incurred under a PPA. It is only weak firms with questionable financial viability that may find it difficult to finance a project, especially if instead of pledging corporate assets as collateral they seek to rely on non-recourse project financing which leaves them with very little incentive to stay with a project in the event that problems develop. If a potential seller is unwilling or unable to accept the regulatory disallowance risk in financing a project, it may indeed find it difficult to obtain willing investors; but that does not make it appropriate to shift the risk to FPL and its customers. If this Regulatory Modifications provision were to exclude such financially weak entities, unwilling or unable to accept risk, from providing proposals, it would work to effectively protect FPL's customers from undue exposure to risk.

Potential sellers with solid investment-grade bond ratings can effectively obtain financing by pledging corporate assets. Such sellers present far less risk to FPL's customers, for they have greater ownership in the success of the project and would have more incentive to work through any project difficulty that may arise.

FPL has several power purchase agreements that include terms identical and/or similar to the Regulatory Modifications provision included in FPL's RFP, and the developers were able to finance the projects. See Exhibit 7 for the list of such contracts.[20] Moreover, in the last year's Supplemental RFP when the IPP industry was reeling with downgrades and other financing challenges, FPL received thirteen eligible proposals and only four took an exception to the terms

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[20] PACE is uncharacteristically accurate when it states in its Objection that FPL declined to provide this list at the September 4, 2003 pre-bid workshop. FPL declined then because the purpose of the workshop was to aid potential bidders in understanding how to complete the required bid forms so that they satisfied RFP requirements. This list was not necessary or relevant to that discussion. PACE attempted to use that proceeding for an improper purpose, conducting discovery to assist it in formulating its objections. FPL declined to subvert the purpose of the meeting. However, now that the information is relevant, FPL is more than willing to share it.

contained in the Regulatory Modifications provision. This is compelling evidence that inclusion of such a provision does not prevent financing.

PACE alleges that it is unfair, onerous and unduly discriminatory to place all risk associated with disallowance of cost recovery incurred under a PPA on a power seller. FPL disagrees. The risk of disallowance should align with the potential to earn a return. In a utility self-build option, it is the utility which earns a return on its investment and which also assumes all the risk of regulatory disallowance. In a PPA it is the seller, not FPL, that has the prospect of earning a return, and that is where the risk of disallowance should be as well.

Furthermore, the seller is the performing party under the contract for which specific costs may be disallowed, and the utility was required to solicit proposals that led to such a contract under the Bid Rule. In addition, the Commission would have approved the terms of such a contract as a condition precedent to the contract taking effect, and except as specified in the contract, FPL has no control over the seller's conduct or performance, and any disallowance would have been caused by actions or omissions not under the control of FPL. Therefore, as between FPL and a contract seller, the risk of disallowance of recovery of specific costs incurred under a PPA arising out of an RFP conducted under the Bid Rule appropriately rests with the seller. Since it is the seller that has both the opportunity to earn a return and control over its performance, it is fair and appropriate that the seller assume the associated risk. PACE effectively acknowledges this risk is minimal when it argues in its Objection that the Equity Adjustment risk factor should be reduced because of "the extremely fair treatment that the Florida PSC has given IOUs in rate recovery." PACE Objections at 20.

PACE erroneously states that the Regulatory Modifications Provision "create a means for FPL to escape from a market contract in the future" by seeking an exclusion of cost recovery from rates. PACE Objections at 7. This is totally inconsistent with the obligation that this provision imposes on FPL to use reasonable efforts to defend and uphold the validity of the contract and its right to recover from its customers all payments required to be made by FPL, and to cooperate with the seller in that effort.

Finally, the implementation of the Bid Rule does not assure FPL of recovery. Costs incurred under a PPA resulting from an RFP can still be disallowed under the Bid Rule. Under the Bid Rule, even if the Commission has approved a PPA resulting from an RFP, costs under that approved PPA may be disallowed (a) if not prudently incurred, or (b) there is evidence of fraud, mistake or similar grounds. Given that a PPA resulting from an RFP under the Bid Rule would have to be approved for cost recovery by the Commission before it becomes effective, it is difficult to conceive of costs payable under that contract not being prudent. The only scenario FPL can conceive of where an imprudent cost might be incurred would be where the seller passed a cost to FPL that was not consistent with the terms of the PPA and FPL failed to note this but the PSC caught it and disallowed it. If such a cost were deemed imprudent, the disallowance should fall to the seller which passed an improper cost to FPL, not with FPL for failing to catch the error. Similarly, if there were mistake, fraud or similar conduct by the seller that resulted in a disallowance, clearly the risk of such a disallowance should fall to the seller and not FPL. So, even under the amended Bid Rule there is a minimal risk of disallowance, and ultimately the risk of such disallowance fairly should flow to the entity that has performance accountability and an opportunity to earn a return - the seller.

II
FPL's Responses To Objection Regarding RFP Terms And Conditions That Are Not Minimum Requirements

PACE has raised one objection regarding RFP terms and conditions that are not Minimum Requirements. This objection misconstrues one term of the sample PPA, which is Appendix A to the RFP.

Before addressing the specific objection, it is important to note that the draft PPA does not pose additional mandatory terms and conditions over the relevant minimum requirements stated in RFP Section III. E. The RFP makes it very clear that exceptions may be taken to each of the terms that are not part of the minimum requirements. The Draft PPA is meant to create a "level playing field for all bidders in developing their proposals and conducting negotiations." FPL stated in the RFP:

> Proposers should consider the draft PPA contains the key elements FPL considers are necessary. Any proposed revisions to the draft PPA must be set forth in the proposal as discussed in Section III.F. Concerns regarding the draft PPA language will be addressed through a negotiation process with Finalists.

RFP Section II. C., page 9.

FPL also provided Proposers with the opportunity to state exceptions to any terms of the RFP and PPA that were not Minimum Requirements. RFP Section III. F. FPL explicitly noted that the purpose of this was to facilitate negotiations.

Given that all the terms and conditions in the RFP and PPA other than the Minimum Requirements stated in the RFP are negotiable and Proposers may take exceptions to them, FPL respectfully submits that the Commission should not entertain any objections regarding these terms and conditions based on arguments that they are onerous, unfair, unduly discriminatory or commercially infeasible. The Commission has encouraged negotiation of contracts as a result of an RFP rather than prescribing terms and FPL has put forth a document that will facilitate such negotiations. Objections asking the Commission to require FPL to remove these negotiable, non-mandatory terms are nothing more than attempts to involve the Commission in negotiations that may not even materialize if the entities raising the objections are not selected as finalists. PACE's objection is premature, unnecessary and an obvious request to have the Commission intrude into matters it has chosen to leave to negotiations between parties.

A. Cash Deposit Provision (PACE Objection K)

In the sample PPA attached to FPL's RFP as Appendix A, Section 4.3 creates a Security Account into which all cash deposits or other liquid security required of the Seller shall be deposited "for the benefit of FPL." RFP Appendix A, p. 20. PACE has objected to the non-mandatory, negotiable provision in the PPA arguing that the interest that accrues on such deposits should not accrue to FPL's benefit.

PACE's objection is based upon an incorrect interpretation of Section 4.3 on page 20 of the sample PPA. That section does not state that FPL will earn interest on the funds a Seller would deposit into a Security Account. All that the negotiable Section 4.3 requires is that the Security Account be established by the Seller "for the benefit of FPL." It does not address interest.

Section 4.3 requires that the control of the Security Account be determined by a control agreement in form and substance acceptable to FPL, to be negotiated when the account is established. Such control agreement would govern the terms and conditions associated with disbursements of funds from the Security Account. The fact that the account is for the benefit of FPL does not mean, and PACE should not have assumed, that the control agreement would make FPL, rather than the Seller, the entity to whom interest, if any, would inure.

Remember, this contractual provision is negotiable. The Proposer may state an exception to the language proposed by FPL and offer alternative language. There is no need for the Commission to address this negotiable term which PACE misinterpreted.

III
FPL's Responses To Objections Pertaining To FPL's Evaluation Methodology

FPL has provided an extraordinarily detailed description of its evaluation methodology. See RFP Section IV, Appendices B, C and E, Attachment Two. PACE has filed several objections to FPL's evaluation methodology and asked the Commission to prohibit FPL from employing what it considers to be an appropriate evaluation methodology to assess all costs necessary to determine the most cost-effective alternative.

In addition to the caution FPL urged earlier about PACE asking for relief not contemplated under the Bid Rule in a proceeding not set forth in the APA, the Commission should realize that it is being asked to switch its historic role. Historically, under Chapter 366 and the Bid Rule, the Commission has assumed the role of reviewing the prudence of utility conduct after the fact. In the Bid Rule this has meant reviewing the economic evaluation after it has been performed. PACE asks the Commission, without the benefit of any evidence, to abandon its historic review role and prescribe the evaluation methodology FPL is to employ. This unprecedented change in the Commission's role is unwarranted, and, if followed, it would result in the selection of an alternative that is not the most cost-effective alternative for FPL's customers. Indeed, some of the changes advocated would have changed FPL's next planned generating unit. This is an unprecedented and unwarranted intrusion into the evaluation role that FPL should correctly retain because it has the obligation to serve.

A. FPL's Southeast Florida Location Preference (PACE Objection A)

In its RFP, FPL has stated it has a location preference for new generating capacity to meet its 2007 need - Southeast Florida. Consistent with the Bid Rule that requires the best available information regarding system-specific factors such as preferred locations and transmission constraints, FPL devotes three pages of its RFP to explaining the factors that led it to have a preference to adding new generation capacity in Southeast Florida to meet its 2007 need. It supplements that detailed explanation by providing the address to FPL's OASIS website where there is an explanation of the load/generation imbalance, related transmission constraints underlying FPL's stated geographic preference and a definition of the Southeast Florida area.

PACE has raised an objection regarding FPL's Southeast Florida location preference. PACE argues that this location preference unfairly favors FPL's self-build options and unduly discriminates against any generation asset located anywhere else in the state. Without any explanation or support, PACE argues that FPL's evaluation will "penalize" any proposal located outside of the Southeast Florida region.

Unsubstantiated hyperbole aside,[21] FPL's location preference complies with the Commission's Bid Rule. The Bid Rule explicitly recognizes the appropriateness of a location

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[21] One particularly egregious example of PACE's hyperbole begs to be specifically addressed. PACE states that "[p]otential competitors were given inadequate time to locate a suitable site in the Southeast Florida region." Objection at 5. It should be noted that this statement acknowledges there are suitable sites in Southeast Florida for power plants, even though earlier in its objection PACE suggested just the opposite. Indeed, there are available sites in Southeast Florida, as evidenced by at least three facts: (1) In FPL's 2001 RFP, 25 of the 81 proposals received were from plants sited in Southeast Florida: (2) In the Spring/Summer of 2001, FPL had 14 different requests in its Generator Interconnection Service Queue for plants in Southeast Florida: and (3) FPL is aware, from its site procurement efforts, that there are undeveloped sites in Southeast Florida suitable for power plant development.

More importantly, PACE's argument is seriously flawed. The 60 day period set forth in the Bid Rule between soliciting and selecting proposals is not meant to provide time for procuring sites. Responsible, competitive developers should secure sites based on known preference and the consideration of transmission constraints. See, Rule 25-22.082(5)(g) ("preferred locations proximate to load centers, transmission constraints"). Independent of the Bid Rule, the Commission has previously recognized that the location of a generating unit and associated transmission limitations are appropriate considerations in an economic analysis. *In re: Petition for Determination of need for Electrical Power Plant (Amelia Island Cogeneration facility) by Nassau Power Corporation,* 92 FPSC 2:814, 820-21 (Order No. 25808), *rehearing denied* 92 FPSC 7:340 (Order No. PSC-92-0678-FOF-EQ).

It is important to understand just what FPL's geographic preference is and is not. The geographic preference is not a refusal to accept proposals from outside of Southeast Florida. FPL will accept all such proposals, and if they prove to be the most cost-effective option or part of a portfolio that is FPL's most cost-effective option, FPL will advance them to negotiations. The geographic preference does not impose a penalty on proposals from outside of Southeast Florida by arbitrarily assigning them costs. FPL will apply a thoroughly documented economic analysis to every competitive portfolio, FPL's or a Proposer's, regardless of location, to determine total costs. The geographic preference is not some non-price factor that will be applied in the non-economic evaluation. The geographic preference is the result of recognition of two factors that are properly disclosed to potential Proposers before they submit a proposal. First, it is a recognition that the Southeast Florida load/generation imbalance and associated transmission costs are a system-specific problem that needs to be addressed. Second, it is a recognition that when these known system-specific conditions are properly reflected in the

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conditions well before a utility issues a solicitation. If they fail to do so, they should be accountable to their shareholders for malfeasance. As FPL discusses in Section III. C. hereafter, FPL has repeatedly, publicly disclosed the system-specific load/generation imbalance in Southeast Florida through means responsible developers should have consulted for at least ten months. The suggestion that FPL should defer accepting bids so PACE and its members can go out and perform tasks they should have been performing for months is inane.

economic analysis, all other things being equal, capacity additions in Southeast Florida, whether FPL or non-FPL, appear to be more cost-effective.

FPL did not decide upon a geographic preference and then construct an economic evaluation that assured a certain geographic answer.[22] FPL constructed an economic analysis that was designed to address known system conditions - a need for 1066 MW system-wide in 2007 as well as a growing load/generation imbalance and associated transmission constraints in 2007 - and then proceeded to determine its most cost-effective alternative. Knowledge of system-specific conditions that needed to be addressed and the results of that economic analysis led FPL to conclude that it should state a geographic preference for generating unit additions in Southeast Florida.

There is an incontrovertible fact that a significant imbalance exists between load and installed generation capacity in the Southeast Florida area. See RFP at 3-5. This imbalance will continue to grow through 2007, because load will grow and there are no scheduled generation additions in the area between now and 2007. Given the projected load growth in that area and the limits of transmission import capability into that area, FPL projects that either generation capacity will have to be added in that area or transmission upgrades will have to be made as early as 2007. Without one or both options, there will be severe transmission constraints in the Southeast Florida area.

Once FPL identified the system conditions that needed addressing, FPL then determined the proper economic analysis necessary to identify the most cost-effective option available to

[22] FPL did not begin its 2007 planning with a location preference in Southeast Florida. Indeed, most of FPL's available power plant sites are located outside of Southeast Florida, and some enjoy cost advantages relative to Turkey Point, which will require significant investment in gas pipeline facilities. Note that PACE did not object to consideration of this location-related cost, that works to the disadvantage of FPL's self-build option.

serve FPL's customers. FPL had already been incorporating transmission integration costs associated with projects in its analysis, but the Southeast Florida imbalance suggested that FPL needed to start considering transmission losses as well as the increased operating costs associated with having to inefficiently operate units in Southeast Florida.

When FPL evaluated its most cost-effective self-build option to meet 2007 needs using these economic analyses, FPL identified the Turkey Point combined cycle option as the most cost-effective. If FPL had ignored known costs associated with transmission losses and efficient unit operating costs, FPL would have selected a unit outside of Southeast Florida. In other words, if FPL had ignored known costs, FPL would not have selected its most cost-effective self-build option.

It is this same economic analytical approach that led to the selection of the Turkey Point combined cycle unit that FPL will employ to evaluate RFP proposals. In that evaluation the Turkey Point unit will compete head to head with the most cost-effective RFP proposals or combinations of proposals.

PACE would have the Commission direct FPL to ignore real circumstances with associated costs that affect FPL's customers, and it reaches the illogical conclusion that ignoring such costs would benefit customers. If FPL were to ignore known costs that affect its customers, FPL probably would not select the most cost-effective alternative; FPL has already learned this from its evaluation of its self-build options.

FPL has designed its transmission analysis in this RFP to appropriately capture and analyze the transmission-related costs arising from potential portfolios which would impose additional costs on FPL's customers. The siting of new generation in Southeast Florida appears to be the most cost effective solution to the growing imbalance between generation and load in this area of FPL's service territory. The transmission related costs and analyses outlined in Appendix E to the RFP are fair, appropriate and necessary to insure the delivery of the most cost-effective alternative for FPL's customers.

FPL's geographic preference for Southeast Florida is entirely warranted given system-specific conditions that need to be addressed and the cost impact those conditions will have on the economic analysis. FPL should not be criticized for disclosing this relevant information to Proposers, as required by the Bid Rule.

B. FPL Has Not Tried To Reserve Transmission Capacity (PACE Objection H)

In RFP Section I. F., FPL communicates the reasons underlying the need for new generation to be located in the Southeastern region of its territory in 2007. Near the end of that discussion (page 6), FPL discusses an "additional factor" that it considered in reaching its conclusion that the Southeast Florida generation/load imbalance should be addressed in 2007. FPL noted that the addition of new generating capacity in 2007 would ease anticipated transmission constraints not only in 2007 but also beyond 2007, providing transmission capability in future years which might be used to carry solid fuel options, if cost-effective, that would improve FPL's fuel diversity.

In its effort to make FPL's RFP as seemingly sinister as possible, PACE's objection to this paragraph of the RFP grossly misconstrues it as a "reservation of transmission capacity." PACE compounds its misrepresentation by saying that this passage penalizes and discriminates against sites located outside of Southeast Florida for a future event that might not occur. It concludes its vitriol with the gratuitous and totally unsupported observation that this passage is "anticompetitive."

When one dispassionately looks beyond PACE's rhetoric, several factors become clear. First, this discussion was included in the RFP by FPL to meet the amended Bid Rule's requirement. Second, the only transmission costs FPL is including in its economic analysis are costs associated with the options it will be analyzing; FPL will not be analyzing or imputing to any option transmission costs associated with future capacity options. Third, FPL is not reserving transmission capacity for any future capacity addition; it is simply attempting to explain how an action to correct a problem in 2007 may impact future planning decisions. Fourth, FPL, is not penalizing or discriminating against projects located outside of Southeast Florida, and certainly not for a "*future* event" ... "*that may well not ever occur.*"

The recently amended Bid Rule requires FPL to disclose "the best available information regarding system-specific conditions which may include, but not be limited to, preferred locations proximate to load centers, transmission constraints, the need for voltage support in particular areas, and/or the public utility's need or desire for greater diversity of fuel source." Rule 25-22.082(5)(g), Florida Administrative Code. Because FPL has indicated a location preference, transmission constraints and a fuel diversity preference in its RFP, all the factors that led it to stating its RFP preferences needed to be disclosed in the RFP. Thus, the inclusion of this paragraph is actually contemplated under the Bid Rule.

It is critically important that this discussion not be misconstrued into something it is not - the imputation of costs associated with a future addition to options being considered in this analysis or a reservation of transmission capacity for a future option. **The only transmission costs FPL will quantify in its economic analysis in the RFP will be the transmission costs related to the generation options it will be evaluating.** Those costs will be calculated the same way, regardless of whether the option is FPL's or a Proposer's. There is no penalty or discrimination against options because of who will build them or where they are located. Recognizing real costs is not a penalty or discrimination. The transmission-related costs to be calculated in FPL's economic evaluation are not the costs associated with capacity additions that may or may not be made in the future on FPL's system. Those costs will be properly addressed in the future when those decisions are made, but they are not a part of the analysis in this case. The transmission related costs in FPL's analysis will be only the costs associated with the options being evaluated to meet FPL's 2007 need.

Just as FPL is not including transmission-related costs associated with future capacity additions in its economic analysis in this RFP, FPL is not attempting to reserve transmission capacity for those future additions. Indeed, it cannot do so.

The paragraph to which PACE objects is not, if fairly read, an attempt to reserve transmission capacity for a future transmission option. It is an observation of what should be obvious. If FPL adds generating capacity in 2007 and this relieves the load/generation imbalance and associated transmission constraints in Southeast Florida in 2007, this relief will continue into the future until load growth offsets the increased generation available. Until that occurs, there will be transmission capacity available to import into Southeast Florida.

How this available transmission capacity may be used in the future is not being committed in this RFP. It might be used to move IPP power into Southeast Florida in future years. It might also be used to move coal-fired or other fuel diverse power provided by an IPP, FPL or another utility. Because FPL has stated a preference for increasing fuel diversity on its system, it was appropriate to discuss in this RFP that this continuing advantage arising from addressing the 2007 load/generation imbalance might be available to help address fuel diversity.

That candid observation did inform FPL's thinking, but it is not a commitment to any future option or a commitment of transmission capacity that may become available to a future option.

FPL is charged with the responsibility to conduct proper resource planning for all future resource needs, and it devotes significant resources to executing this important function. Part of that exercise is to anticipate the impact of today's decisions on future options - options that may occur as well as options "*that may very well not occur*." Where current decisions can be made that not only support immediate needs but also support and preserve options for future conditions that may benefit FPL's customers, FPL has a charge to consider such options.

FPL could have justified a more restrictive approach. It could have limited its 2007 RFP to Southeast Florida locations. That would have assured that all the new capacity additions would offset the Southeast Florida load/generation imbalance, and it would have assured that the resulting favorable impact on transmission import capability into Southeast Florida was available for future additions. Instead, FPL is allowing bids from Proposers regardless of location. This does not assure that transmission import capability into Southeast Florida will be increased.

FPL has adopted an economic evaluation that will capture the transmission-related costs of all proposals on an equivalent basis. That does not mean that all options analyzed will have equivalent costs. It means that all options will be analyzed the same way. FPL expects that there will be variations in the transmission-related costs, but that is not a penalty or discrimination, that is a recognition that various projects will have different transmission costs due to their locations. By including an analysis method that recognizes transmission-related costs, FPL's customers are assured of not only having the most cost-effective option for 2007, but also a transmission system in 2007 and beyond that can reliably deliver capacity and energy. If FPL were to ignore or disregard such costs in its analysis, customers could be saddled with an option that is not the most cost-effective, and they might be saddled with a transmission system that has serious constraints that adversely affect customers' reliability and costs.

C. The RFP's Recognition of the Costs of Transmission Losses and Increased Operating Costs of Southeast Florida Generation (PACE Objection G)

FPL sets forth its economic evaluation in detail in its RFP. See RFP Section IV, Appendices B, C and E, Attachment Two. Attachment E discusses FPL's transmission cost assessment. Two of the elements FPL will be analyzing are transmission losses and increased operating costs associated with dispatch of generating units because of transmission constraints.

PACE alleges that FPL's recognition of actual costs that will arise from transmission losses and dispatch of gas turbines in Southeast Florida due to transmission constraints is onerous and unduly discriminatory. PACE provides no credible support for a conclusion that these features of the RFP violate the Bid Rule. PACE conveniently overlooks and makes no attempt to contest the fact that these costs are a real cost of service borne by FPL's customers. FPL addresses each argument included in this section of PACE's Objections below.

First, PACE states "it is noteworthy that FPL did not include transmission losses in the RFP issued for the Manatee and Martin self-build options approved by this Commission." PACE then indulges in pure and rampant speculation regarding the outcome of the prior RFP by offering unsupported conjecture on the effect of transmission losses on the Martin and Manatee self-build options only. PACE Objections, at 15.

The issue before the Commission now is not what was or was not analyzed in FPL's last RFP or whether the option selected in the RFP would change if the analysis changed. The issue before the Commission is much more straight forward: whether the inclusion of transmission losses in FPL's economic analysis in this RFP violates the Bid Rule. Clearly, it does not. The Bid Rule does not prohibit or preclude consideration of transmission losses in an RFP analysis.

Losses are a real cost of service borne by FPL's customers. Load flow simulations conclusively demonstrate that the amount of generation needed to serve a given amount of load varies depending on the electrical location of the generator(s) serving a given load (FPL). Additional transmission losses result in a need for additional generation capacity and increased energy costs throughout the year.

Additionally, the losses assessment is not discriminatory since it is applied to all capacity options, including FPL's, using the same methodology. Transmission losses can be quantified and converted to costs. The purpose of the Bid Rule is to identify the best, most cost-effective alternative to serve customers. The recognition of transmission losses in an RFP analysis improves the evaluation of cost effectiveness and is entirely consistent with the Bid Rule.

The inclusion of a losses assessment in this RFP is an important and appropriate improvement of FPL's RFP process and economic analysis in order to better identify and consider costs such as losses. While FPL plans to include the impact of transmission losses in all future RFPs, FPL will continue to assess and refine the integral components of an RFP in order to produce the most cost effective alternative for its customers.

PACE's conjecture that consideration of transmission losses "would have altered the outcome of the bid evaluation concluded just six months ago" is specious. PACE's attempt to forecast the outcome of the last RFP is rank speculation.

PACE contrasts a Commission decision made in December of last year in FPL's need case with the establishment of analytical criteria for this RFP, suggesting that a different analytical approach in a six-month lapse in time evidences bias. This contrast is extremely misleading. The analytical approach for the RFPs that culminated in the Commission's decision in December of 2002 was adopted before FPL's initial RFP in August 2001. So, rather than suggest a six-month lapse in time, the proper comparison is essentially twenty-four months.

As a reasonable person would expect, FPL has learned from its efforts in its last RFPs. Also, in this RFP there are other system conditions that need to be addressed. So, FPL has enhanced its analytical approach in this RFP compared to its last RFPs. One factor, however, remains the same; all economic evaluation criteria were and are to be applied in a non-discriminatory manner to all the plans evaluated to find the most cost-effective option for FPL's customers.

In the current RFP, FPL is incorporating improvements in the criteria and economic analysis in order to better identify and consider costs. These improved criteria and methods of analysis, for the purpose of evaluating the capacity options for this RFP, will similarly be frozen at this time to assess the capacity options in a non-discriminatory manner.

The same arguments apply to PACE's Objection to FPL's recognition and consideration of increased operating costs in Southeast Florida. This is another example of an improvement to FPL's RFP process and economic analysis. Consideration and recognition of increased operating costs will enhance the identification of the best capacity option for FPL's customers. Increased operating costs arising from the need to operate Southeast Florida gas turbines instead of other more economic non-Southeast Florida generation in order to maintain reliability are a real cost borne by FPL's customers. These costs will be reduced if new generation is located within the Southeast Florida area. Thus, the identification and inclusion of these costs is reasonable and not discriminatory and is in the interest of FPL's customers.

Without additional generation in Southeast Florida, there will be an increasing need to incur higher costs in the dispatch of Southeast Florida generation to maintain reliability that must be recognized and captured in the economic analysis. The load in Southeast Florida continues to increase each year. Without a corresponding increase in Southeast Florida generation, the Southeast Florida load becomes increasingly dependent upon the transmission system for importing power into this area. This increased dependence results in greater reliance on dispatching of Southeast Florida gas turbines in order to maintain reliability. These costs are real costs that should be captured in the RFP economic analysis on a non-discriminatory basis.

Next, PACE argues that an RFP is unduly discriminatory if it contains characteristics or features that are not found in other RFPs. Specifically, PACE claims that "[n]either the recent RFP issued by Tampa Electric Company, nor the most recent RFP issued by Progress Energy Florida, imposed these unduly discriminatory and restrictive provisions." PACE Objections at 15. Considerations of losses are particularly important to FPL due to the vast geographic expanse of its service territory. Obviously, the Bid Rule does not require public utilities to issue RFPs with identical criteria and features. To the contrary, the Bid Rule envisions a public utility-specific selection process intended to produce the most cost-effective alternative for that public utility's customers.

PACE also asserts that the "need" for 1,100 MW "is not merely a Southeast Florida need, but is an FPL *system* need..." and that the "load centroid" in Southeast Florida is moving north. PACE Objections, at 16. Here again, PACE's misguided complaints do not even attempt to demonstrate a violation of the Bid Rule. Perhaps more importantly, this argument demonstrates a lack of understanding of the RFP and the transmission analysis that will be conducted pursuant to the RFP.

As discussed in the RFP and subsequently explained at the September 2, 2003 Pre-Proposal Workshop, the capacity being sought in the RFP will be modeled from a transmission perspective serving the entire FPL load, which includes the Southeast Florida load. FPL will not be modeling the entire 1066 MW need in 2007 on the assumption that the 1066 MW will serve only the load in Southeast Florida. The transmission assessment will focus on the transmission-related costs associated with integrating the potential capacity options for meeting FPL's 1066 MW system need with all of the rest of FPL's generating units, not just those generating units located in Southeast Florida.

PACE's contention that "the load centroid was indeed moving north, not south or southeast as indicated by this RFP and this specific evaluation criterion" is irrelevant. Even if the "centroid" is moving north (e.g., to Daytona Beach), it is not moving out of Southeast Florida anytime soon. There continues to be a growing imbalance of load/generation in Southeast Florida that is causing increased transmission constraints. A gradual creep of the "centroid" to the north does not change the system-specific condition that needs to be addressed. Based on the latest available ten-year load forecast, over the next ten years the majority of FPL's load growth will be in the Southeast Florida area, and the imbalance between load and generation in this area will only increase if generation is not added within this area. Therefore, the location of the "centroid" is irrelevant.

PACE also claims that "FPL agreed in response to questions at the Pre-Proposal Workshop that a balanced expansion of two 600-MW facilities would have no adverse effect on the transmission system." PACE Objections, at 16. FPL made no such concurrence at the Pre-Proposal Workshop.

In any case, PACE's request that the Commission impose an alternative option of 600 MW in Southeast Florida and 600 MW facilities outside Southeast Florida (based presumably on the centroid moving north) underscores PACE's lack of understanding of the RFP. That very option is available under the RFP. FPL has made a 600 MW Southeast Florida option available for analysis. Proposers can add the other 600 MW block. This advantage accorded Proposers that is not required under the Bid Rule is not even acknowledged by PACE.

Finally, PACE's assertions that the timing of the development of the current load and generation disparity in Southeast Florida somehow makes this RFP "anti-competitive at its very core" should also be summarily rejected. FPL has long recognized that growing load demand in Southeast Florida would eventually require additional generation in that area or increased import capability into the area. Other entities seemed to have also recognized value in siting generation in Southeast Florida based on the fact that during mid-2001 there were fourteen different requests in FPL's Generator Interconnection Service Queue seeking to connect new generators in the Southeast Florida area.[23] These fourteen requests totaled 5383 MWs and were all scheduled to be in-service between June, 2003 and December, 2004.

During the year 2001 transmission assessment, a generation expansion plan for the years 2005 and beyond had not yet been finalized. However, this assessment did not indicate the need for additional generation or transmission upgrades in Southeast Florida through the year 2005, which was the time frame for that assessment since a generation expansion plan beyond that date had not been finalized. During mid-year 2002, once Martin 8 and Manatee 3 were identified as FPL's next planned generating units for the year 2005, FPL began another transmission assessment that looked out beyond 2005.

The initial findings of this new transmission assessment, which became available during the Fall of 2002 (when the criteria and data for the then recently completed RFPs and pending need case had long before been established), led to concerns that the imbalance of load and

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[23] The 14 requests seeking to connect new generators in Southeast Florida are identified in Exhibit 8 as Queue Status Nos. 4, 14, 17, 18, 19, 20, 22, 26, 27, 28, 29, 31, 40 and 41.

generation in the Southeast Florida area, if not mitigated by additional generation or transmission in the 2007-2010 time frame, could result in insufficient transmission capabilities. The concerns associated with the load and generation imbalance for the Southeast Florida area, along with other transmission capability information, were then made available by FPL in November 2002 by the posting of a document entitled "General Information Regarding FPL's Transmission System Capability" on FPL's OASIS website. See Exhibit 9 attached hereto.

As FPL continued to further assess this area and generation expansion scenarios in the 2007 and forward time frame, FPL updated this information. The last update of the document posted on its OASIS website discussing transmission capabilities at different locations on the FPL system was in May 2003. This document contains a general discussion of the generation and load imbalance issue in the Southeast Florida area. See Exhibit 10 attached hereto.

Additionally, FPL's current Ten Year Site Plan issued on April 1, 2003, highlights this issue and references the OASIS website. See RFP Attachment One.

Since November 2002, when FPL posted the first of several public disclosures of this Southeast Florida imbalance and associated transmission constraints, FPL Transmission has not received any inquiries or questions regarding the Southeast Florida area load and generation imbalance. Clearly, the load and generation imbalance in the Southeast Florida area is reaching a point where either additional generation in the Southeast Florida area must be added or transmission facilities constructed in order to increase the import capability into the Southeast Florida area. The fact that FPL is acting to consider this real system condition in its economic analysis after giving more than ten months notice to the IPP industry is hardly evidence of anticompetitive conduct.

<u>D. FPL's Equity Adjustment (PACE Objection I)</u>

Pursuant to Section 25-22.081(7) of the Bid Rule, FPL has indicated its intent to reflect the impact of purchased power on its capital structure in assessing relative cost-effectiveness of competing purchased power proposals. *See* RFP, Section IV.D, p.29, and Appendix C. FPL's application of an Equity Adjustment also reflects consideration of mitigating factors. *Id.*

PACE has objected to the use of an Equity Adjustment, alleging that it is "unfair, onerous, and unduly discriminatory." See PACE Objections at 18-21. PACE's position is based largely on the same arguments it made in FPL's last need case. *See, In re Petition To Determine Need For An Electrical Power Plant in Martin County By Florida Power & Light Company,* 02 FPSC 12:250 (Order No. PSC-02-1743-FOF-EI). In particular, PACE contends that FPL has "[failed] to recognize and value numerous factors that inure to FPL's benefit by entering into a long term PPA." PACE Objections at 18. PACE's arguments in this regard are unconvincing, Again, they are predicated on a fundamental misreading or intentional ignorance of key provisions of the RFP, and they do not in any way support a conclusion that use of an Equity Adjustment constitutes a violation of the Bid Rule.

PACE's objections to the use of an Equity Adjustment essentially are restatements of its position in FPL's last need case that an Equity Adjustment is an unfair means of disadvantaging outside proposals in favor of a utility's self-build option. See Order No. PSC-02-1743-FOF-EI at 20. Although declining to recognize the use of an Equity Adjustment in that case, the Commission rejected the contention that an Equity Adjustment was inherently improper, stating instead that "consideration of an equity adjustment is appropriate." *Id.* Indeed, the Commission stated that "in future dockets, a case-by-case examination of *the entire circumstances surrounding the evaluation of PPAs* . . . and the presence or absence of any mitigating factors shall be considered." *Id.* (Emphasis added.) Thus, if the Commission is to conclude that the Equity Adjustment should or should not be recognized in this instance, it will do so only following the review contemplated in Order No. PSC-02-1743-FOF-EI, -- the scope of which clearly is not contemplated by the abbreviated complaint process in the Bid Rule.[24] Consequently, it cannot reasonably be argued that merely indicating FPL's intention to include the costs of a capital structure impact due to purchased power proposals constitutes a violation of the Bid Rule.

Regarding mitigating factors, the "presence or absence" of which the Commission indicated "shall be considered" in assessing the appropriateness of an Equity Adjustment, and which PACE unabashedly claims FPL intends to ignore in its analysis (PACE Objections at 18, 20), FPL refers PACE to the RFP, Section IV.D, p.29, and Appendix C. The RFP unequivocally states:

> An equity adjustment will be applied for purchase power obligations of more than three years. In conducting such an evaluation relative to the impact of purchased power and the computation of an equity adjustment, *FPL will also consider the presence or absence of mitigating factors.*

RFP, Section IV.D, p.29 (emphasis added). Further, Appendix C indicates:

> While the S & P methodology takes a broad look at the debt equivalence of purchase power obligations, there may be other factors which may be considered as mitigating the effect of such purchased power obligations. . . . These factors will be reflected as credits in the development of a modified equity adjustment factor.

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[24] In fact, recognition of the Equity Adjustment was not necessary for the Commission to conclude that FPL's self-build options were the most cost-effective resource options to meet the 2005-06 needs of FPL's customers. Order No. PSC-02-1743-FOF-EI at 20. Likewise, it may well be that the equity adjustment also is not a dispositive factor in selecting the most cost-effective options to meet the 2007 need.

RFP, Appendix C, I.B, at C-3. FPL then proceeds to explain the basis for and derivation of the mitigating factors on the following five pages of Appendix C, complete with a mathematical example of the calculations and the identification of relevant assumptions. Id., at C-3 through C-8. That PACE and all (or at least those who constitute "some") of its members might have overlooked these materials, embedded squarely in the heart of the explanation and example of the Equity Adjustment, would be quite surprising -- especially given that this item was the subject of questions at the pre-bid workshop.

Beyond the simple fact that FPL has not failed to include potential mitigating factors in the development and application of the Equity Adjustment, it is particularly important to observe that the mitigating factors comprehended by the approach detailed in Appendix C include all of the risks listed by PACE (i.e., "construction cost overruns, permitting risks, equipment failure risks, and risk of equipment performance below certain output or efficiency levels" (PACE Objections, at 20) and more. Specifically, the risks of construction cost overruns, permitting risks, and performance of the undelivered plant are addressed in FPL's Completion Security Mitigation factor. Likewise, the risks associated with equipment failure and performance are addressed in the Performance Security Mitigation factor. Appendix C, pp. C-3 through C-8. Moreover, these mitigation factors rely upon several assumptions that, conservatively developed, operate in favor of Proposers. In alleging that FPL's RFP fails to take into account potential mitigating factors, PACE is grossly misinformed and, in any event, simply wrong.

PACE contends that the risk factor used in the methodology is flawed and concludes, with no visible means of support, that a factor of 10% should be used, rather than the 30% factor used by FPL. On the other hand, in support of the 30% factor, FPL included as Attachment 2 to the RFP, a Standard & Poor's publication describing the criteria that S&P employs when establishing the risk factor to be applied to the net present value of capacity payments.[25]

Since FPL issued its last RFP in which it employed a risk factor of 40%, S&P has revised its methodology for determining the size of the risk factor. S&P now takes a more general approach and, whereas previously the method of cost recovery of purchased power was one of several factors included in its assessment, it now assigns the risk factor based predominantly on the method of recovery of purchased power costs.[26] S&P now assigns utilities with PPAs included as an operating expense in base tariffs a 50% risk factor. However, "[f]or utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of *as low as 30% could be used.*" In certain cases, Standard and Poor's may consider a lower risk factor of 10% to 20% for distribution utilities where recovery of certain costs, included stranded assets, has been legislated." RFP, Appendix 2, Standard & Poor's Utilities and Perspectives, May 12, 2003, at 2-3 (emphasis added).

FPL elected to use 30%, the lowest possible factor specified by S&P for non-distribution without legislatively mandated recovery of stranded assets. In contrast, PACE's proposed 10% factor is offered without a shred of support. It is important to remember that the very real and actual balance sheet impact of FPL entering into additional purchased power obligations will be based on the risk factor S&P uses, not the factor PACE advocates or even the factor that the Commission approves.

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[25] Utilities and Perspectives, Volume 12, No. 19 (May 12, 2003).

[26] Interestingly, in FPL's last need case, the Commission was outspoken in its belief that S&P's methodology in sizing the risk factor did not adequately consider the method of cost recovery of purchased power. S&P's new approach appears to address the Commission's concern.

FPL's Equity Adjustment serves two essential purposes. First, it places RFP proposals on an equal footing with FPL's self-build options so that the net impact of both alternatives is to preserve an incremental 55% equity / 45% debt capital structure. Second, it captures the cost to FPL of restoring its capital structure to its target 55% equity / 45% debt ratio when FPL purchases power and rating agencies impute debt to FPL's capital structure. Thus, it is not a one-sided adjustment. The impact of the FPL self-build option on FPL's capital structure is captured in using an assumed incremental capital structure of 55% equity/45% debt. The Equity Adjustment captures the corresponding impact on FPL's capital structure of purchased power agreements.

PACE does not argue against the central facts underpinning the adjustment: that rating agencies treat purchase power obligations as off-balance sheet debt and that this debt equivalent is included in the financial ratios used to determine credit quality.[27] It also is undeniable that unless some offsetting action is taken, a utility's financial position will erode as a result of the imputed-debt effects from a purchase power contract. Thus, to assess properly the costs of expansion plans containing purchase power contracts, it is necessary to include the cost of additional equity required to rebalance FPL's capital structure to account for the imputed-debt impact of such contracts. In this way, the impact of purchased power on the utility's capital

[27] PACE's argument regarding the declining reliance on purchased power is specious. If no new contracts are added, the expiration of old contracts will reduce the amount of off-balance sheet debt. All else being equal, FPL would be able to achieve a 55-percent adjusted equity ratio with a lower amount of actual equity. If the expiring contracts are replaced with new purchase power agreements, the amount of off-balance sheet debt will not fall as it otherwise would. The economic analysis of resource options, for the purpose of a true comparison, must assess each option on its own merits, and its incremental cost relative to other current options, holding constant the things or factors external to the acquisition of the particular purchased power obligation being considered-- factors such as the amount of existing or forecasted total purchased power from other sources.

structure is held neutral relative to the capital structure assumed in assessing the costs of the self-build options. To do otherwise would ignore the undisputed impact of purchased power on a utility's balance sheet, resulting in an skewed comparison of the relative costs of the self-build and purchased power options by failing to hold the utility's capital structure neutral, and would be tantamount to a subsidy of purchased power.

The Equity Adjustment is an appropriate element of analysis in an economic assessment of the costs associated with purchased power. It is fair and not unduly discriminatory and should be employed. Real costs associated with purchased power agreements simply cannot be ignored, if the most cost-effective option to serve customers is to be identified.

The Commission has previously approved the concept and application of an Equity Adjustment to calculate the cost of the capital structure impact as a result of entering into purchased power obligations. The Commission recognized the underlying concepts 11 years ago in Docket No. 910759-EI, where it concluded that "[c]redit rating agencies recognize that, without compensating factors, increased reliance on purchased power obligations may lower coverage ratios." *See* Order No. 25805. The Commission went on to correctly note that the primary way to offset this is for the utility to increase its equity.[28] More recently in Docket 990249-EG, which involved FPL's Standard Offer Contract, this Commission found it

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[28] PACE quotes "certain pertinent findings" from this case at page 19 of its Objections. PACE's fundamental misapprehension of the reason for applying an equity penalty in this case would explain PACE's misapplication of Order 25805. In that case, Florida Power Corporation ("FPC") argued that it should not entertain bids at all because additional purchased power would result in a downgrade of its credit ratings. Contrary to PACE's implication, this was never and still is not the reason FPL included the equity penalty adjustment in any RFP. In Order No. 25805, the Commission recognized the principles underlying the equity penalty but was unable to conclude that FPC's debt rating would be downgraded as a result of taking on additional purchased power. FPL has not argued in this case that an equity penalty is appropriate because entering into a purchased power contract would lead to a downgrade. The change in the company's capital structure and the associated cost occurs regardless of whether there is a downgrade.

"appropriate to include an equity adjustment when determining FPL's proposed standard offer contract payments." Order No. 99-1713-TRF-EG, at 7. In the 2001 determination of need proceeding for Florida Power Corporation's Hines 2 Plant, the Commission again recognized that "imputed debt is an actual consideration by bond rating agencies," and accordingly recognized the use of an equity penalty adjustment in the evaluation of power supply options. *See* Order No. PSC-01-0029-FOF-EI. And the Commission's own rules require utilities to address the impact of purchases on its capital costs when filing determination of need applications. Rule 25-22.081(7), F.A.C.

For all of the foregoing reasons, it cannot reasonably be argued that the proposed use of the Equity Adjustment by FPL in its evaluation of purchased power proposals constitutes a violation of the Bid Rule. In fact, the <u>only</u> possible purpose served in stripping FPL (before proposals are even submitted) of the opportunity to employ an Equity Adjustment would be to grant Proposers an option to price their proposals higher than they otherwise might have, while preserving the same relative chance of being the low-cost option. This cannot be in the customers' best interests. PACE's Equity Adjustment contentions must be rejected.

IV
FPL's Responses To Objections Regarding FPL's RFP Process

<u>A. FPL's Draft PPA and Exceptions Requirements (PACE Objection F)</u>

In Section II of its RFP, FPL discusses the FPL draft purchased power agreement ("PPA") included as Appendix A to its RFP. See RFP Section II.C., Appendix A. This PPA was not included as a Minimum Requirement to which a Proposer could take no exceptions.

PACE has objected to FPL's inclusion of a draft PPA in its RFP and argued that FPL is attempting to impose a PPA on bidders without the benefit of negotiations. In making its argument, PACE attacks FPL's statement that failure to state exceptions and pose alternative terms shall be deemed acceptance of the terms of the PPA. PACE also suggests that FPL does not disclose the effect of taking exceptions would have on a proposal. PACE closes its argument with the suggestion of having to state any exceptions now when negotiations are not scheduled to begin until January 2004 is unreasonable.

Once again, PACE has either misunderstood or chosen to mischaracterize FPL's position. By including a draft PPA, FPL is not attempting to impose a PPA on Proposers without the benefit of negotiation. The Draft PPA allows meaningful comparisons of proposals by assuring that all proposals are compared on the same basis, so that negotiations with each short-listed Proposer may begin from common terms and conditions.

Other than the Minimum Requirements, all terms and conditions in the draft PPA are negotiable, although Proposer's exceptions will be considered in the non-economic comparison of proposals. In other words, to allow FPL to effectively compare proposals, conduct its non-economic risk assessment of proposals and to facilitate potential negotiations, Proposers must take exceptions to specific terms they find objectionable and propose alternative language.

No attempt has been made to force Proposers into a "take it or leave it" proposition with respect to the draft PPA. Rather the draft PPA and the RFP represent a significantly detailed description of the expectations and intended commercial framework that FPL considers on the whole to be an adequate representation of the characteristics necessary to define a purchase power arrangement. Exceptions (and alternative language) to all of the elements of this representation, including the draft PPA, must be identified early in the process to allow FPL to assess the probability of being able to come to a mutually agreeable position in subsequent negotiations. In the absence of such an assessment, FPL could miss an opportunity to seek and obtain timely clarification and explanation that would help FPL effectively compare proposals.

The draft PPA is meant to be a template to which revisions can be proposed in the form of objections and alternative language. FPL explained this in its RFP:

> Proposers should consider the draft PPA contains the key elements FPL considers are necessary. Any proposed revisions to the draft must be set forth in the proposal as discussed in Section III.F. Concerns regarding the draft PPA language will be addressed through a negotiation process with finalists.

RFP Section II. C., page 9. That this process is intended to facilitate, rather than foreclose, negotiations is made clear in the RFP:

> Inclusion of this information with the proposal will facilitate negotiations by allowing FPL to evaluate the specific core issues of the exceptions, rather than addressing generic or conceptual comments. FPL reserves the right to request from a Proposer whether and to what extent FPL's contemplated rejection of a particular exception would affect pricing.

RFP Section III. F., page 26. Such information will allow FPL to put every submittal on the same page and assess differences among proposals on non-economic terms. For these reasons, this approach is commonly used in Requests for Proposals.

The sole basis for PACE's argument that a PPA is being forced on potential bidders without the benefit of negotiations is the language that says that if an exception is not taken to a term or condition, it is considered accepted. FPL's RFP is not unique in stating:

> Failure to state exceptions and pose alternative language shall constitute acceptance of the terms and conditions set forth in the RFP and/or PPA.

RFP Section III. F., page 26.

Interestingly, the RFP included as PACE's Exhibit 4 - Duke Power's Request for Proposals, dated January 28, 2003, includes a similar provision:

> TERMS and CONDITIONS

> Duke Power has included certain Terms and Conditions in the "model" Power Sale Agreement (PSA) and Collateral Annex of this RFP. By submitting a bid proposal, the respondent agrees that these Terms and Conditions will become part of any agreement reached between Duke Power and the bidder. Should the respondent wish to take exception to any of these Terms and Conditions, the exception must be explained in writing as part of the proposal.

Pace's Exhibit 4, page 5. The provision is repeated on page 6 of the Duke RFP, with the added requirement that a bidder also "must state how each exception changes pricing of the proposal."[29]

By including the draft PPA, FPL is making known the terms and conditions it believes are appropriate for inclusion in a PPA. By asking Proposers to identify terms to which they object and to provide alternative language, FPL is simply asking them to do the same. Such a process accomplishes several goals. It allows: (1) Proposers the opportunity to prepare their submittal based on full disclosure of the draft PPA; (2) Proposers to indicate exceptions to and alternative language for any and all terms and conditions that are not Minimum Requirements; (3) for a dialogue relative to specific terms and conditions during the evaluation period; (4) for a more meaningful comparison of competing proposals; and (5) FPL to assess the risk associated with entering into a successful PPA with each Proposer.

Throughout the proceedings that led to the most recent amendments to the Bid Rule, much discussion centered on the desire for more transparency in the bidding process. FPL's decision to include a draft PPA as part of the RFP adds to the transparency of the process. Potential participants will have more information to develop their submissions, and as a result, their submittals and FPL's analysis will be more robust. Further, Proposers will be aware of

[29] See also Exhibit 11 with excerpts from other RFP's issued by Long Island Power Authority and Portland General Electric Company having similar provisions.

FPL's position on the contractual balance of risks and benefits to guide the development of their submittals and so may factor that allocation into their prices.

In suggesting that taking exceptions to the PPA will penalize the proposal, PACE has grossly mischaracterized the evaluation process and FPL's statements on the subject. Further, PACE fails to acknowledge that the opportunity to note exceptions and propose alternative language represents an opportunity to improve a proposal in comparison to other alternatives.

PACE has completely misrepresented the statements made by Ms. Delia Perez-Alonso on behalf of FPL at the pre-proposal workshop held September 2, 2003, as can be readily seen from the transcript pages included in PACE Exhibit 1. There is absolutely no affirmation that a proposal that takes exceptions to the draft PPA will be penalized in either the economic or non-economic evaluation, as represented by PACE at page 14 of their Objections to Florida Power & Light's Request for Proposals. FPL has stated that exceptions will not be considered in the economic evaluation. Exceptions are to be considered in the non-economic evaluation in which FPL will conduct a non-quantitative risk assessment of the exceptions taken. Proposals that exhibit strong potential in the economic evaluation will be considered for a Panel Review. The RFP states:

> The Panel Review would be an interview-style exchange between the Proposer(s) and FPL panelists representing the non-economic evaluation areas. This will allow a more complete exchange of ideas in the important areas.

RFP Appendix B, page B-8. This is consistent with the information provided in the September 2, 2003, pre-bid workshop where FPL stated repeatedly that exceptions to the draft PPA would not be penalized in the economic evaluation, but rather would be used in an assessment of the risk of entering into a successful PPA. See PACE Exhibit 1, page 25.

The RFP also notes that the draft PPA is specifically tailored to a power purchase from a new combined-cycle, gas-fired generation facility. The RFP expressly contemplates that the draft PPA would need to be revised to accommodate other alternatives not subject to the Siting Act. RFP Section II. C., page 9.

Finally, PACE objects that the requirement that potential bidders state exceptions to the draft PPA within 60 days as part of their proposal is unfair. This is a curious objection in light of the fact that the Duke RFP attached to PACE's Objections has the same requirement but the timeline for submitting bids is 45 days rather than the 60 days provided in the FPL RFP.[30] Clearly, potential Proposers can better prepare their proposals by being able to take into account the terms and conditions in the draft PPA, which clarifies and amplifies many of the general terms stated in the RFP. Likewise, the evaluation and negotiation process is facilitated by knowing the Proposers' positions on the terms and conditions in the draft PPA.

FPL's customers also will be far better off if Proposers are required to put their requested changes to FPL's proposed terms and conditions "on the table" from the beginning, rather than after a short list has been announced. Requiring comprehensive comments up front will reduce the temptation to Proposers to submit a low-ball bid and then, during subsequent negotiations, try to force unexpected or onerous concessions on FPL that could put its customers at risk -- or cause FPL to lose valuable time by turning to higher-priced bidders and beginning negotiations all over again.

In addition, Proposers are better off having 60 days to review the draft PPA, provide exceptions and propose alternative language, rather than being presented with a draft PPA once

[30] PACE Exhibit 4, the Duke RFP, states at page 5: "Should the respondent wish to take exception to any of these Terms and Conditions, the exception must be explained in writing as part of the proposal." The timeline for the Duke RFP provides for the release of the RFP on January 28, 2003, and the due date for proposals is March 14, 2003.

they have been short-listed with only 11 days to provide their Best and Final Offers and provide exceptions to and alternative language for a PPA. In FPL's most recent RFP, the draft PPA was provided only to bidders on the short list. In the subsequent Need Determination, intervenors other than the entities on the short list claimed that FPL failed to negotiate in good faith with the short-listed bidders because of the short time to review the draft PPA. One of the entities who made that argument was represented by the same legal counsel that now represents PACE.

The requirement to state exceptions and propose alternative language is very much an opportunity. Proposers can suggest revisions which will enhance their proposal vis-a-vis other alternatives. It should not be assumed that providing revisions can only decrease a proposal's chance of success. It may very well increase the chances of success. FPL cannot definitively state how it will evaluate exceptions and assess the risk they represent until it learns of the nature and extent of exceptions.

FPL has made it clear that all the terms and conditions in the RFP and PPA, except the Minimum Requirements, are negotiable, although exceptions will be considered in the non-economic evaluation comparing different proposals. The terms and conditions are indicative of those FPL would press for in negotiations. Requiring Proposers to state their objections and propose alternative language allows a more meaningful comparison of alternatives and facilitates subsequent negotiations. It is common for RFPs to require exceptions and alternative language to be submitted at the same time as a proposal. Proposers are in no way disadvantaged or prejudiced by such a requirement in the evaluation or the negotiating processes. This Commission should resist any request to venture into the negotiating process by relieving Proposers of the requirement of stating their objections to and alternative language for the PPA as part of their proposal.

B. Cutoff Date For Submitting Questions (PACE Objection L)

PACE objects that the September 23, 2003, cutoff date for submitting questions in response to the RFP is "unfair." It argues that Proposers will not receive the fuel forecast to be used in the RFP until September, and the cutoff date for website questions is September 23, 2003, so Proposers should be given a cutoff date 14 days after release of the fuel forecast. PACE's objection appears to be limited to questions about the fuel forecast.

FPL is surprised to see such a minor issue brought to the Commission as an objection, particularly since it was not first presented to FPL. In both the pre-issuance meeting on August 21, 2003 and the Pre-Bid Workshop on September 2, 2003, the schedule was discussed, and the question cutoff date was specifically mentioned without objection. The purpose of the cutoff date is to allow all questions and answers to be posted in a time frame that supports access for all participants to the information.

In response to a suggestion from a participant at the pre-issuance meeting, FPL amended the planned release of the fuel forecast so Proposers would have the exact fuel forecast that will be used in the evaluation as they prepare their proposals. Having made that change and having heard no other expressed concern, FPL had no reason to believe PACE or its members had a problem with the question cutoff date.

FPL did not intend to create problems for participants by accommodating a suggestion regarding the release date of the fuel forecast, and it is not convinced that it has. Nonetheless, FPL will extend the cutoff date for questions to September 30, 2003, or 14 days after release of the fuel forecast, whichever occurs later.

CONCLUSION

As the foregoing discussion shows, only two of PACE's objections regarding FPL's August 25, 2003, RFP have any merit. If these two issues (cutoff date for website questions on fuel and the dual fuel requirement) had been raised with FPL prior to PACE filing an objection with the Commission , FPL would have considered them. Unfortunately, they were not.

The remainder of PACE's objections lack any merit, and PACE's presentation of them with its casual disregard for factual accuracy and its irresponsible allegations of motive, serves no legitimate purpose. FPL's RFP complies with the Commission's Bid Rule and in some instances goes beyond the requirements of the Bid Rule to the benefit of potential Proposers. There is no basis, factual or legal, to provide any of the relief requested by PACE.

Respectfully submitted,

R. Wade Litchfield
Senior Attorney
Florida Power & Light Company
P.O. Box 14000
700 Universe Boulevard
Juno Beach, Florida 33408

John T. Butler
Steel Hector & Davis LLP
200 S. Biscayne Boulevard
Suite 4000
Miami, Florida 33131

Susan Clark
Radey Thomas Yon & Clark P.A.
313 N. Monroe St., Suite 200
Tallahassee, Florida 32301

Ken Hoffman
Rutledge, Ecenia, Purnell & Hoffman, P.A.
215 S. Monroe St., Suite 420
Tallahassee, Florida 32302

Charles A. Guyton
Steel Hector & Davis LLP
Suite 601, 215 S. Monroe St.
Tallahassee, Florida 32301

By: Charles A. Guyton
Charles A. Guyton

EXHIBIT 1

Moody's, *Default and Recovery Rates of Corporate Bond Issuers*

Special Comment

February 2003

Contact	Phone
New York	
David T Hamilton	1 212 553 1653
Praveen Varma	
Sharon Ou	
Richard Cantor	

Default & Recovery Rates of Corporate Bond Issuers

A Statistical Review of Moody's Ratings Performance, 1920-2002

Summary

This report is Moody's 16th annual study of global corporate defaults and ratings performance. Moody's reviews the default, recovery and credit loss experience of 2002 and for the historical period since 1920. Briefly, we find:

- Worldwide, 141 Moody's-rated corporate bond issuers defaulted on a total of $163 billion in 2002. Thirty-six issuers defaulted on over $1 billion each, quadrupling the 1983-2001 average real size of default to $1.7 billion.
- Default rates measured as a percentage of issuers generally fell in 2002, while default rates measured as a percentage of dollar volume surged. Moody's global issuer-weighted default rate fell to 3.0% in 2002 from 3.8% in 2001. On a dollar volume-weighted basis, the default rate increased from 4.2% in 2001 to 5.3% in 2002.
- Moody's speculative-grade default rate forecasting model indicates that over the next year the global issuer-weighted speculative-grade default rate will fall by just over one percent, from 2002's 8.3% to 6.9% at the end of 2003.
- The percentage of issuers downgraded reached record highs in 2001 and 2002. 25% of US issuers rated speculative-grade 2002 were downgraded, while 22% of US investment-grade rated issuers were downgraded. The percentage of investment-grade rated issuers that became fallen angels reached a peak of 5.2% in 2002, up from just over 2% in 2001.
- Sovereign bond issuers experienced an overall improvement in credit quality in 2002. No sovereign bond issuers defaulted in 2002, and 15 sovereign bond issuers were upgraded compared with only three downgrades.
- Though no commercial paper (CP) issuers defaulted in 2002, CP issuers were downgraded from the P-1 and P-2 rating categories at a particularly high rate in 2002.
- The average recovery rate for defaulted bonds was 34.4% of par measured on issue-weighted basis and 25.6% on a dollar-weighted basis in 2002. Excluding telecommunications bonds, the average recovery rates were 39.3% and 33.6%, respectively.
- Recovery rates show a strong negative correlation with default rates measured as a percentage of the dollar volume outstanding, indicating that credit loss rates rise when defaults increase.

Historical Speculative-Grade Default Rate Extrema

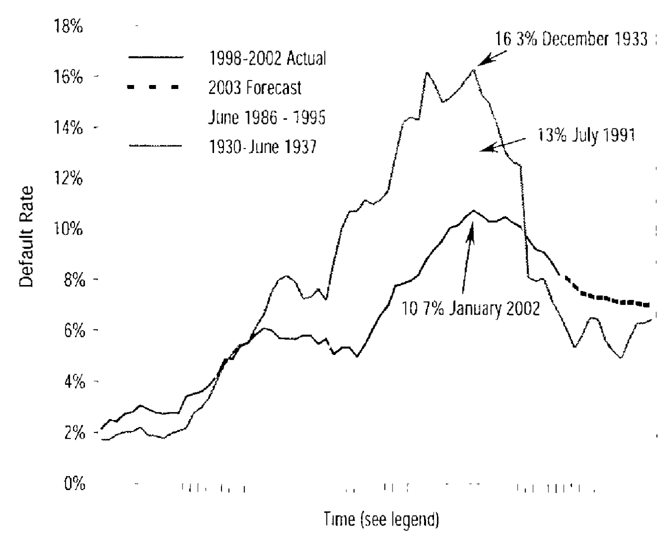

Exhibit 43 – Average Cumulative Issuer-Weighted Default Rates from 1-20 Years by Whole Letter Rating, 1920-2002

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Aaa	0.00	0.00	0.02	0.09	0.19	0.29	0.41	0.59	0.78	1.02	1.24	1.40	1.61	1.70	1.75	1.85	1.96	2.02	2.14	2.20
Aa	0.07	0.22	0.36	0.54	0.85	1.21	1.60	2.01	2.37	2.78	3.24	3.77	4.29	4.82	5.23	5.51	5.75	5.98	6.30	6.54
A	0.08	0.27	0.57	0.92	1.28	1.67	2.09	2.48	2.93	3.42	3.95	4.47	4.94	5.40	5.88	6.35	6.63	6.94	7.23	7.54
Baa	0.34	0.99	1.79	2.69	3.59	4.51	5.39	6.25	7.16	7.99	8.81	9.62	10.41	11.12	11.74	12.33	12.95	13.49	13.93	14.39
Ba	1.42	3.43	5.60	7.89	10.16	12.28	14.14	15.99	17.63	19.42	21.06	22.65	24.23	25.61	26.83	27.96	29.13	30.24	31.14	32.05
B	4.79	10.31	15.59	20.14	23.99	27.12	30.00	32.36	34.37	36.10	37.79	39.37	40.85	42.33	43.62	44.94	45.91	46.68	47.32	47.60
Caa-C	14.74	23.95	30.57	35.32	38.83	41.94	44.23	46.44	48.42	50.19	52.30	54.40	56.24	58.22	60.08	61.78	63.27	64.81	66.25	67.59
Investment-Grade	0.17	0.50	0.93	1.41	1.93	2.48	3.03	3.57	4.14	4.71	5.30	5.90	6.46	7.00	7.48	7.92	8.30	8.65	8.99	9.32
Speculative-Grade	3.83	7.75	11.41	14.69	17.58	20.09	22.28	24.30	26.05	27.80	29.47	31.08	32.64	34.07	35.36	36.58	37.72	38.78	39.67	40.46
All Corporates	1.50	3.09	4.62	6.02	7.28	8.41	9.43	10.38	11.27	12.14	13.01	13.85	14.66	15.40	16.07	16.69	17.24	17.75	18.21	18.64

Exhibit 44– Average Global Cumulative Issuer-Weighted Default Rates from 1-20 Years by Whole Letter Rating, 1970-2002

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Aaa	0.00	0.00	0.00	0.04	0.12	0.21	0.30	0.40	0.52	0.64	0.77	0.92	1.08	1.17	1.27	1.39	1.51	1.65	1.65	1.65
Aa	0.02	0.03	0.07	0.16	0.26	0.36	0.46	0.57	0.65	0.73	0.83	1.01	1.21	1.49	1.64	1.82	2.08	2.31	2.65	2.96
A	0.02	0.09	0.22	0.36	0.51	0.68	0.86	1.07	1.31	1.56	1.82	2.07	2.33	2.57	2.90	3.29	3.70	4.16	4.67	5.17
Baa	0.22	0.61	1.08	1.69	2.25	2.81	3.38	3.94	4.58	5.26	6.00	6.80	7.60	8.41	9.24	10.03	10.87	11.63	12.25	12.73
Ba	1.28	3.51	6.09	8.76	11.36	13.74	15.66	17.60	19.46	21.29	23.35	25.56	27.67	29.63	31.36	33.31	35.03	36.62	37.92	39.15
B	6.51	14.16	21.03	27.04	32.31	36.73	40.97	44.33	47.17	50.01	52.31	54.28	56.25	58.17	59.72	60.97	61.35	61.35	61.35	61.35
Caa-C	23.83	37.12	47.43	55.05	60.09	65.22	69.26	73.88	76.50	78.54	80.92	80.92	80.92	80.92	80.92	80.92	80.92	80.92	80.92	80.92
Investment-Grade	0.08	0.24	0.45	0.72	0.98	1.25	1.52	1.81	2.13	2.47	2.83	3.22	3.63	4.04	4.47	4.93	5.42	5.90	6.37	6.79
Speculative-Grade	4.99	10.05	14.66	18.67	22.18	25.18	27.73	30.00	31.99	33.92	35.89	37.84	39.72	41.47	42.99	44.60	45.93	47.11	48.08	49.02
All Corporates	1.59	3.19	4.64	5.90	6.96	7.85	8.62	9.32	9.96	10.60	11.25	11.92	12.58	13.21	13.81	14.45	15.07	15.65	16.19	16.67

Exhibit 45 – Average U.S. Cumulative Dollar Volume-Weighted Default Rates from 1-5 Years by Whole Letter Rating, 1994-2002

	1	2	3	4	5
Aaa	0.00	0.00	0.00	0.00	0.00
Aa	0.00	0.00	0.00	0.00	0.00
A	0.96	1.63	2.30	2.83	3.45
Baa	1.49	3.12	4.41	6.10	6.99
Ba	1.09	3.56	6.71	9.17	11.30
B	7.12	15.00	20.66	24.68	27.65
Caa-C	36.28	45.38	50.85	54.86	55.89
Investment-Grade	0.96	1.80	2.56	3.38	3.98
Speculative-Grade	7.70	13.98	18.82	22.34	24.79
All Corporates	2.60	4.92	6.89	8.53	9.70

EXHIBIT 2

Press Accounts of Mirant and NRG Bankruptcies and NEG Plant Sales

News

Headquarters
Mirant Corporation
1155 Perimeter Center West
Atlanta GA 30338
USA

Current news releases

Mirant (ticker: MIR, exchange: Other OTC) News Release - 8/28/03

Mirant Files Court Motion On Pepco Agreement

Motions and Orders	Download
Order for Extending Temporary Restraining Order	(127 KB)
Order for Temporary Restraining Order	(152 KB)
Motion to Reject Agreement	(37 KB)
Request for Temporary Restraining Order	(56 KB)

Print this page

- Mirant seeks to reject an agreement to purchase power from Pepco
- Mirant seeks to renegotiate two agreements to sell power to Pepco
- Mirant continues to generate power in the D.C. and Maryland area

ATLANTA, Aug. 28 /PRNewswire-FirstCall/ -- Mirant announced today it has filed a motion with the U.S Bankruptcy Court in the Northern District of Texas, which is overseeing its Chapter 11 case, to reject an out-of-market agreement to purchase power from Pepco. Pepco is an electricity distribution company serving the District of Columbia and the neighboring Maryland suburbs. Mirant is also seeking to renegotiate the terms of two out-of-market agreements to sell power to Pepco

As a Chapter 11 debtor-in-possession, Mirant has an obligation to review, and take action on, unfavorable contracts that may reduce the company's ability to provide value to its stakeholders. Under the agreement Mirant now seeks to reject, the company is obligated to purchase power from Pepco at prices that are significantly out-of-line with market prices for power, requiring Mirant to pay substantially more than market rates. Mirant forecasts it would cost the company and its stakeholders hundreds-of-millions of dollars over the duration if this agreement if it were to remain in effect. The obligations under this agreement will run out over time and end in 2021.

"Mirant has filed this motion with the Court to fulfill legally-mandated obligations to its stakeholders," said Marce Fuller, president and chief executive officer, Mirant. "Importantly, the rejection will have no effect on Mirant's ongoing generation and sale of power into the PJM marketplace. These actions will not affect Pepco's ability to purchase power and provide reliable electric service to its customers in the District of Columbia and Maryland."

In order to protect the Court's control over the rejection process, Mirant also obtained an injunction preventing Pepco and the Federal Energy Regulatory Commission from initiating any conflicting proceedings pending the resolution of the motion

The two power sales agreements that Mirant is seeking to renegotiate with Pepco require Mirant to sell power for substantially less than current market rates. From today through their expiration -- one agreement expires in June 2004 and the other in January 2005 -- these agreements would cost Mirant tens- of-millions.

"Although these power sales agreements are due to expire in a relatively short time, our strong desire is to renegotiate -- not reject -- these agreements," said Fuller. "However, if we are unable to renegotiate, Mirant may only be able to fulfill its Chapter 11 duties by rejecting these agreements, as well."

Mirant is a competitive energy company that produces and sells electricity in North America, the Caribbean, and the Philippines. Mirant owns or controls more than 22,000 megawatts of electric generating capacity globally. We operate an integrated asset management and energy marketing organization from our headquarters in Atlanta. For more information, please visit www.mirant.com .

Special Note Regarding Forward-Looking Statements

This press release contains statements that are forward-looking within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Such forward-looking statements are only predictions and are not guarantees of future performance. Investors are cautioned that any such forward-looking statements are and will be, as the case may be, subject to many risks, uncertainties and factors relating to the operations and business environments of Mirant and its subsidiaries that may cause the actual results of the companies to be materially different from any future results expressed or implied in such forward-looking statements.

Factors that could cause actual results to differ materially from these forward-looking statements include, but are not limited to, the following: the ability of the companies to continue as going concerns; the ability of the companies to operate pursuant to the terms of the debtor-in-possession facility; the companies' ability to obtain court approval with respect to motions in the Chapter 11 proceeding prosecuted by it from time to time; the ability of the companies to develop, prosecute, confirm and consummate one or more plans of reorganization with respect to the Chapter 11 cases; risks associated with third parties seeking and obtaining court approval to terminate or shorten the exclusivity period for the companies to propose and confirm one or more plans of reorganization, for the appointment of a Chapter 11 trustee or to convert the cases to Chapter 7 cases; the ability of the companies to obtain and maintain normal terms with vendors and service providers; the companies' ability to maintain contracts that are critical to its operations; the potential adverse impact of the Chapter 11 cases on the companies' liquidity or results of operations; the ability of the companies to fund and execute their business plan; the ability of the companies to attract, motivate and/or retain key executives and associates, the ability of the companies to attract and retain customers. Furthermore, as its securities are no longer listed on a securities exchange, Mirant cannot guarantee that there will be a continued liquid trading market for its securities.

Additionally, other factors should be considered in connection with any Forward Looking Statements, including other risks and uncertainties set forth from time to time in Mirant's reports filed with the United States Securities and Exchange Commission. Although we believe that the expectations and assumptions reflected in the forward-looking statements are reasonable based on information currently available to our management, we cannot guarantee future results or events. We expressly disclaim a duty to update any of the forward-looking statement.

SOURCE Mirant

CONTACT: media, James Peters, +1-678-579-5266, or investors, John Robinson, +1-678-579-7782, or Stockholder inquiries, +1-678-579-7777, all of Mirant

Web site: http://www.mirant.com
(MIRKQ)

PG&E National Energy Group.

RESTRUCTURING EFFORTS | NEWS | ABOUT CHAPTER 11 | PLAN OF REORGANIZATION

PRESS RELEASE

July 8, 2003

NEWS MEDIA CONTACT:
Natalie Wymer, 301/280-5654

EDITORS: *Please do not use "Pacific Gas and Electric" or "PG&E" when referring to PG&E Corporat subsidiary, PG&E National Energy Group, Inc. PG&E National Energy Group is not the same compai Pacific Gas and Electric Company, the utility, and is not regulated by the California Public Utilities Commission. Customers of Pacific Gas and Electric Company do not have to buy products or servic PG&E National Energy Group in order to continue to receive quality regulated services from Pacific Electric Company*

PG&E NATIONAL ENERGY GROUP, INC.
TO REORGANIZE UNDER CHAPTER 11 PROTECTION
Action Taken With Support of Major PG&E NEG Creditors

BETHESDA, Md. As the next step in their ongoing restructuring efforts, PG&E National Energy Gr (PG&E NEG), PG&E Energy Trading Holdings Corporation (PG&E ET) and PG&E ET subsidiaries toda voluntarily filed petitions for protection under Chapter 11 of the federal bankruptcy code. Separate New England, Inc. (USGenNE) filed its own petition for Chapter 11 relief. Today's filings in the U.S. Bankruptcy Court for the District of Maryland are in keeping with PG&E NEG's previously announce intention to maximize cash and reduce liabilities as part of its ongoing effort to restructure debt ob

Other PG&E NEG entities - including PG&E Gas Transmission Northwest and PG&E Generating, whic several independent power generation facilities across the country - have not filed for Chapter 11 protection. Operations are expected to continue as normal at these facilities and at facilities owned USGenNE. PG&E NEG is a subsidiary of PG&E Corporation (NYSE: PCG), which is not a party in the 11 proceedings.

With the agreement in principle of major creditors as to its key terms, PG&E NEG also filed a Plan c Reorganization. This group includes informal bondholders, as well as agents under certain unsecur facilities, acting in their individual capacities. The plan anticipates that PG&E Corporation will have interest in PG&E NEG or any of its subsidiaries after the Chapter 11 reorganization is approved by t and implemented. Instead, equity in a reorganized PG&E NEG would be distributed proportionately unsecured creditors as a component of a plan distribution package that would include cash, new de securities and common stock. However, PG&E Corporation may continue to provide certain service interim basis, including the administration of employee benefits. It is anticipated that a Chapter 11 the PG&E ET entities will be filed at a later date. Similarly, USGenNE's debt will not be restructured of the PG&E NEG plan, but will be dealt with at a later date.

PG&E NEG also announced today that Joseph Bondi, currently the company's chief restructuring of assume the role of chief executive officer, in addition to his current duties, subject to court approv NEG President Thomas B. King has resigned and will remain with PG&E Corporation.

"For several months, with our creditors, we have made steady progress toward restructuring PG&E Energy Group's obligations," said Bondi, chief executive officer designate of PG&E NEG. "While the much work to be done, we believe that today's action is another step in moving forward and resolv challenges that our financial situation and current market conditions present. We concluded, along lenders, that filing Chapter 11 protection provides the best opportunity to reach a resolution that is long-term interests of our employees, the creditors and our other stakeholders."

PG&E Corporation announced in May that the ongoing restructuring of PG&E NEG would be implem through a Chapter 11 bankruptcy to facilitate an orderly negotiation among creditors, which includ bank syndicates, with approximately 40 banks and bondholders. The company estimates that clair asserted against PG&E NEG may exceed $4 billion.

PG&E NEG is in default under various recourse debt agreements and guaranteed equity commitmei totaling nearly $3 billion. In addition, other PG&E NEG subsidiaries are in default under various det agreements totaling approximately $2.5 billion, but this debt is non-recourse to PG&E NEG.

As a result of the sustained downturn in the power industry and like a number of merchant energy businesses, PG&E NEG experienced a financial downturn. This caused the major credit rating agenc downgrade credit ratings to below investment grade. Although PG&E NEG's operating performance during 2002, the company took a loss of $3.4 billion for the year, including the impairment charges to the planned sale, transfer or abandonment of investments associated with the merchant powe generation operation. These were steps affirmatively taken to restructure the business

First Day Motions
In conjunction with the filing today, PG&E NEG will seek approval from the Bankruptcy Court for a "first day motions" enabling the company to continue to manage its businesses in the ordinary cou first day motions include requests for permission to continue payments for affected employee payr health benefits, and retain legal, financial and other professionals to assist the company through th Chapter 11 process.

The company fully expects to continue to meet various employee payrolls and provide for continue employee health care and other benefits. Employees' qualified retirement savings plan accounts ar affected by the filing, as they are held in a trust and protected by federal law. The company also e: continue paying vendors and suppliers in full for goods and services provided after the filing.

Due to the company's cash on hand of approximately $114 million as of May 31, 2003, PG&E NEG need to arrange for debtor-in-possession financing. While the company expects to continue most o during bankruptcy, operations and staffing levels will be affected as the company seeks to minimiz and conserve cash.

Moving Forward
"Our goal is to continue to work constructively with the creditors to reorganize these businesses, w include valuable assets that are performing well, in a way that maximizes their value and enables t operations to emerge from Chapter 11 as viable businesses going forward." Bondi said

As previously reported for the past several months, PG&E NEG has significantly reduced its energy operation Today's Chapter 11 filing of PG&E ET entities will facilitate the next major step toward n financial resolution and the wind-down of the trading subsidiaries.

USGen New England
While USGenNE also has filed Chapter 11 in the Maryland bankruptcy court, its case is being separ administered. The company estimates that claims asserted against USGenNE will exceed $1 billion

PG&E NEG and USGenNE will continue to work with creditors to address the future of the USGenNE which include. Brayton Point Station, Somerset, Mass.; Salem Harbor Station, Salem, Mass.; Manc Street Station, Providence, R I.; Bear Swamp facility, Rowe, Mass.; Connecticut River Hydroelectri in New Hampshire and Vermont; and Deerfield River Hydroelectric System in Massachusetts and Vi It still remains likely at this time that the company will sell or transfer USGenNE, as it previously re

Restructuring Efforts To Date
Today's filings follow months of aggressive actions by PG&E NEG and its subsidiaries to abandon, s transfer assets and significantly reduce energy trading operations in an ongoing effort to raise cast reduce debt, whether through negotiation with lenders or otherwise. Efforts to date and as previou reported, include:

- Sold the 66.6 megawatt Mountain View wind-powered generation facility in the San Gorgon near Palm Springs, CA, to Centennial Power, Inc. for $102.5 million

- Sold one-half of its 50 percent interest in the Hermiston Generating plant to Sumitomo Cor and Sumitomo Corporation of America for a pre-tax gain of approximately $23 million. The plant, located in Hermiston, OR, continues to be operated and managed by subsidiary of PG&E NEG

- Sold the 176-megawatt, natural gas-fired Spencer Station Generating facility in Denton, TX nearby Lake Lewisville hydroelectric facility for about $2 million to the City of Garland, TX

- Sold the Canadian energy trading operation, ET Canada, to Seminole Canada Gas Company

Reduced the aggregate value of the energy trading portfolio by more than 70 percent. The compai limited its asset trading and risk management activities to only what is necessary for energy mana services to facilitate the transition of the company's merchant generation facilities through their sa transfer or abandonment. Ultimately, PG&E NEG will reduce and transition to only retain limited ca to ensure fuel procurement and power logistics for the company's retained independent power pla operations

- Agreement in principle to transfer three power plant construction projects - Athens Generat (Athens, NY), Covert Generating (Covert, MI), and Harquahala Generating (Tonopah, AZ) - respective lenders or their designees. While the transfers have not yet been completed, fun been provided for these projects to be completed and today's Chapter 11 filings are not ex have any affect on those projects.

- Agreement in principle to transfer three power projects - La Paloma Generating (McKittrick, Millennium Power (Charlton, MA) and Lake Road Generating (Killingly, CT) - to the respecti lenders or their designees. While these transfers have not yet been completed, today's Cha filings are not expected to have any affect on those agreements or the day-to-day operatio these facilities.

- Pending sale of the 149-megawatt Ohio power peaking facilities to AMP-Ohio for approxima million. It is expected to be completed by August 31, 2003, following necessary regulatory approvals.

About PG&E NEG
Headquartered in Bethesda, MD, PG&E NEG employs approximately 1,800. The company's more th megawatts of generation include a mix of natural gas, coal/oil, hydroelectric, waste coal and wind numerous facilities across the country. With more than 1,350 miles of gas pipelines, the company's Northwest system has the ability to transport 2.9 billion cubic feet of natural gas per day from cost competitive, abundant supplies in Western Canada to markets in California, Nevada and the Pacific Northwest. The company also owns the 80-mile North Baja pipeline in Southern California, which capacity to ship 500 million cubic feet of natural gas from U.S. producing regions to markets in Nor Mexico and Southern California.

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This news release discusses certain matters that may be considered "forward-looking" statements meaning of Section 27A of the Securities Act of 1933, as amended, including statements regarding intent, belief or current expectations of PG&E National Energy Group and its management. Actual f results could differ materially from those expressed or implied in any forward-looking statements. National Energy Group describes in its filings with the U.S. Securities and Exchange Commission sc the key factors that could cause actual results to differ materially.

Southeast Power Report

October 14, 2002

SECTION: POWER MARKETS; Pg. 2

LENGTH: 590 words

HEADLINE: NRG FAILURE TO MAKE $ 47M PAYMENT PUTS PLANTS THAT BACK BONDS AT RISK

BODY:

NRG Energy Oct. 1 failed to make a $ 47-million interest payment on $ 800-million in bonds issued by its NRG South Central LLC subsidiary, putting at risk its holdings in 14 energy projects in southeast and south central states that had been used to back the bonds.

NRG said it was negotiating with the bondholders and financial groups to resolve the default and there was no immediate indication that the bondholders would exercise rights to foreclose on the assets.

However, the situation aroused interest from regulators and other parties -- especially in Louisiana where much of the NRG holdings are concentrated.

NRG South Central is based in Baton Rouge and operates or has interests in 10 plants in Louisiana, Texas, Mississippi, Oklahoma and Florida with 4,890 MW of capacity.

It also has had several projects in construction or delayed totaling about 2,500 MW. NRG had originally planned to build up its portfolio in the region to between 8,000 MW and 10,000 MW by 2005.

The existing projects back the $ 800-million in bonds and theoretically could be taken over by the bondholders as last resort to settle the debt. NRG had also announced in August that it hoped to divest all its South Central assets as soon as possible to help resolve its debt problems, but so far no asset sales have been announced.

NRG said in August it planned to transfer a half-built 1,192 MW gas combined-cycle merchant project in Holmesville, Miss., to Shaw Group to resolve a construction debt. But that transaction has never been completed.

NRG South Central's biggest holding is 1,950 MW of generation capacity at the Big Cajun 1 and Big Cajun 2 sites in Louisiana which includes capacity purchased from the bankrupt Cajun Electric Power Cooperative in 2000 for $ 1-billion and new peaking capacity added at one of the sites.

The former Cajun plants operated by NRG subsidiary Louisiana Generating supply power under long-term contracts to eleven former Cajun cooperatives and four of those cooperatives are now asking the Louisiana Public Service Commission to extend the existing contracts 10 more years to 2014. The seven other cooperatives have 25-year deals with NRG dating from 2000.

While the commission has not yet finished the case, the PSC members will decide at an Oct .16 meeting whether they should hire an outside legal advisor to cover bankruptcy issues and help NRG's utility customers in the state defend their rights.

In another development Shaw Group petitioned the PSC Sept. 25 to become a party the case saying it was "vitally concerned " about the continued financial viability of Louisiana Generating.

Other operating NRG South Central projects include an 837-MW gas combined-cycle plant in Batesville, Miss.; the 633-MW gas-fired Brazos Valley unit in Thompsons,Tex.; the 400-MW gas-fired McClain project in New Castle, Okla.; the 320-MW gas-fired Bayou Cove peaking unit in Jennings, La.; a 50% share in the 420-MW Sabine River project in Orange, Texas; a 202-MW gas-fired peaking project in Sterlington, La.; a 25% share in the 485-MW Mustang gas-fired project in Denver City, Texas; and holdings totaling 45-MW in three small cogeneration plants in Oklahoma and Florida.

NRG South Central projects on hold include the 1,192-MW Holmesville gas-fired combined-cycle plant; a 600-MW coal-fired unit at the Big Cajun 2 plant in New Roads, La.; a 292-MW addition at the Batesville, Miss., plant; and a 545-MW gas combined-cycle project in Mesquite, Texas.
URL: http://www.platts.com

LOAD-DATE: October 24, 2002

EXHIBIT 3

Standard & Poor's, *Ratings Direct*, for Calpine Corporation

Research:

Return to Regular Format

Calpine Corp. Credit Rating Lowered Three Notches to 'B'

Publication date: 02-Jun-2003
Credit Analyst: Jeffrey Wolinsky, CFA, New York (1) 212-438-2117, Peter Rigby, New York (1) 212-438-2085

NEW YORK (Standard & Poor's) June 2, 2003--Standard & Poor's Ratings
Services lowered its corporate credit rating on Calpine Corp. to 'B' from 'BB'.

In addition, Standard & Poor's lowered its rating on Calpine's secured debt to 'B' from 'BB', on Calpine's senior unsecured debt to 'CCC+' from 'B+', and on Calpine's convertible preferred securities to 'CCC' from 'B'.

Also, the rating on the secured revolver and the secured term loan is lowered to 'BB-' from 'BBB-', two notches above Calpine's corporate credit rating. The two-notch elevation on the secured revolver and the secured term loan reflects a very strong likelihood of 100% recovery of principal in the event of a default or bankruptcy. The outlook remains negative.

"The rating downgrade is directly attributable to Calpine's deteriorating financial performance in the face of its growing debt burden and persistently weak electricity margins," said credit analyst Jeffrey Wolinsky. "In addition, Calpine's business risk continues to worsen as it continues to build new power plants and shift its portfolio toward the more volatile merchant power sales and away from the more predictable contracted power sales," he added.

Calpine's credit statistics have significantly deteriorated and overall business risks have increased. For example, adjusted funds from operations interest coverage dropped from 2.2x in 2001 to 1.5x in 2002, significantly below expectations. Calpine's proposed monetization of contractual revenue and sales of assets with contractual revenues will increase cash flow volatility since merchant revenues will make up a larger portion of available cash. Calpine faces considerable liquidity issues through 2004 with $6.7 billion in potential refinancing and about $3.1 billion in planned capital expenditures. The company has limited opportunities to
reduce its debt burden and is taking on more debt in order to fund its construction program. In order to meet its liquidity needs, Calpine must generate cash from sources other than operating cash flow. Calpine plans to meet these requirements through a combination of asset sales and debt financings, which carry execution risk. Calpine's target of 65% leverage to total capitalization makes the company vulnerable to electricity price

volatility and to capital market access. Calpine's inability to access the equity markets has led to debt levels over 70%. Adjusted debt levels are expected to remain above 70% over the next five years.

Nonetheless, the following strengths adequately mitigate the above risks at the 'B' rating level: Calpine's contractual revenue base mitigates some of the cash flow volatility that merchant power sales cause. Calpine has proven its ability to operate its power plants in an efficient manner, with average availabilities of over 90%, including multiple newly constructed units. Calpine has proven its ability to manage and construct multiple plants in a timely and efficient manner. Highly efficient gas turbines increasingly make up a larger percentage of Calpine's fleet, which should ensure a higher level of dispatch compared to the older plants that Calpine's competitors have purchased over the past few years.

The negative outlook reflects Calpine's considerable liquidity needs through 2004 and the execution risk of raising needed cash through a combination of asset sales and debt financings. Should Calpine's financial performance deteriorate further, which would include a move toward higher leverage than anticipated, or if the company cannot refinance nearing maturities soon, or both, the ratings could be lowered.

Complete ratings information is available to subscribers of RatingsDirect, Standard & Poor's Web-based credit analysis system, at
www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; under Fixed Income in the left navigation bar, select Credit Ratings Actions.

STANDARD &POOR'S	RATINGSDIRECT

Research:
Summary: Calpine Corp.

Return to Regular Format

Publication date: 28-Aug-2003

Credit Analyst: Jeffrey Wolinsky, CFA, New York (1) 212-438-2117; Peter Rigby, New York (1) 212-438-2085

Credit Rating:	B/Negative/--

■ Rationale

Standard & Poor's Ratings Services' 'B' corporate credit rating on Calpine Corp., a San Jose-based corporation engaged in the development, acquisition, ownership, and operation of power generation facilities, reflects the following risks:

-- Calpine's credit statistics have significantly deteriorated. For example, adjusted funds from operations (FFO) interest coverage dropped to 1.5x in 2002 from 2.2x in 2001, which is significantly below expectations. The deterioration is due to lower power prices on the merchant portfolio and higher levels of debt than anticipated. In addition, Standard & Poor's expectation over the next five years is that minimum and average adjusted FFO interest coverage ratios will not exceed 1.3x and 1.9x, respectively, assuming no additional development. However, Standard & Poor's expects FFO-to-interest coverage to remain above 1x, even under a severe stress scenario.

-- Overall business risks have increased. Calpine's proposed monetization of contractual revenue and sales of assets with contractual revenues will increase cash flow volatility because merchant revenues will make up a larger portion of available cash.

-- Calpine faces considerable liquidity issues through 2004 with $3.7 billion in potential refinancing and about $3.1 billion in planned capital expenditures.

-- Calpine has limited opportunities to reduce its debt burden and has taken on more debt to fund its construction program.

-- To meet its liquidity needs, Calpine must generate cash from sources other than operating cash flow. Calpine plans to meet these requirements through a combination of asset sales and debt financings, which carry execution risk.

-- Calpine's target of 65% leverage to total capitalization makes the company vulnerable to electricity price volatility and to capital market access. Calpine's inability to access the equity markets has led to debt levels over 70%. Adjusted debt levels are expected to remain above 70% over the next five years.

Nonetheless, the following strengths somewhat mitigate the high level of risk:

-- Calpine's contractual revenue base mitigates some of the cash flow volatility that merchant power sales cause. The contracts, which are mostly with utilities and other load-serving entities, have a seven-year average life and have a weighted average credit quality of 'BBB+'.

-- Calpine has proven its ability to efficiently operate its power plants, with average availabilities of more than 90%, including multiple newly constructed units.

-- Calpine has proven its ability to manage and build multiple plants in a timely and efficient manner. Calpine has successfully built its projects on time and within budget. Calpine can standardize the design of its plants and achieve economies of scale in design and maintenance because most of the new plants are combined-cycle facilities, using "F" turbine technology.

-- Highly efficient gas turbines increasingly make up a larger percentage of Calpine's fleet, which should ensure a higher level of dispatch compared with the older plants that Calpine's competitors have purchased over the past few years.

Calpine's current operating portfolio, principally in the U.S., consists of 86 operating projects with a net ownership interest in 20,089 MW. Calpine's development and growth strategy seeks to capitalize on opportunities in the power market through an ongoing program to acquire, develop, own, and operate electric power generation facilities or interests in such facilities, and marketing power and energy services to utilities and other end-users.

Liquidity.

As of June 30, 2003, Calpine had about $418 million of cash and short-term investments. In mid-July 2003, Calpine closed on a $3.8 billion corporate financing, which includes a $500 working capital facility that replaces the existing working capital facilities. The $300 million revolver is priced at LIBOR plus 400 basis points (bp) and matures on July 15, 2005. The $200 million term loan is priced at LIBOR plus 350 bp and matures July 15, 2007. About $130 million of the proceeds from the term loan was used to cash collateralize existing letters of credit.

Liquidity will continue to be somewhat of a concern for Calpine through 2004. Calpine faces $3.7 billion in potential refinancing and about $3.1 billion in potential capital expenditures. Meeting these liquidity needs involves execution risk for the company. Calpine needs to sell assets or obtain external financing to meet its obligations.

■ Outlook

The negative outlook reflects Calpine's weak financial ratios, considerable liquidity needs through 2004, and the execution risk of raising needed cash through a combination of asset sales and debt financings. If Calpine's financial performance deteriorates further, which would include a move toward higher leverage than anticipated, or if the company cannot refinance nearing maturities soon, or both, the ratings could be lowered.

EXHIBIT 4

Requests for Proposals Requiring Minimum Credit Ratings

IDAHO POWER COMPANY

REQUEST FOR PROPOSALS
UPDATED RELEASE: MARCH 14, 2003

MINIMUM REQUIREMENTS FOR PROPOSAL

All proposals must meet the minimum requirements set forth below. IPCo, in its sole discretion, may reject any proposal that fails to respond adequately or completely to all or any part of this RFP.

SECTION 1 - MINIMUM CREDIT REQUIREMENTS

Respondent or Guarantor of Respondent must possess a senior unsecured debt rating, issued or reaffirmed within the last 12 months, of no less that "BBB-" from Standard & Poor's or "Baa3" from Moody's at the time of proposal. The Respondent must be able to provide audited year-end financial statements for all specific entities proposing to contract with Idaho Power Company and any guarantor(s) within 120 days following the end of each fiscal year. The Respondent must be able to provide performance assurances in the event IPCO believes Respondent's ability to perform or creditworthiness has become unsatisfactory. The Respondent must be willing to grant a present and continuing security interest in any performance assurances or cash equivalent collateral. Respondent must be willing to enter into credit protection conventions similar those included the EEI master agreement.

SECTION 2 - CAPACITY AND ENERGY REQUIREMENTS

To meet the need of 100 MW of capacity and related energy, during the months of June, July, August, November and December, IPCo will accept bids for fully dispatchable, first call, non-recallable, physically delivered capacity and related energy from a resource within the IPCo Control Area. IPCo will consider proposals of less than the requested quantity as identified in this RFP provided that IPCo can combine such proposals, at the discretion of IPCo with other proposals to accumulate the necessary capacity. Capacity and energy offered in excess of the requested amount will be considered, but the value of any surplus will be determined at IPCo's sole discretion.

1. New generation proposals must meet all Western Electricity Coordinating Council Reliability Management System requirements including periodic generator testing. All associated costs are the responsibility of the Respondent.

2. Any new on-system generation must have automatic voltage control with at least a 90 percent power factor capability and a power system stabilizer.

3. Proposals that require construction of a generation resource will require a reasonable demonstration of Respondent's ability to obtain both the necessary land use permits and any required air quality and water consumption and discharge permits.

4. The proposal must completely describe all dispatch and scheduling flexibility IPCo will have. Respondent must describe provisions that can and would be made to allow IPCo to dispatch the energy directly from IPCo's control area energy management control system (EMS) and Respondent will be responsible for all associated costs.

5. The capacity must be available no later than June 1, 2005. IPCo's requirements are anticipated to extend throughout the planning horizon. Proposals must include, at a minimum, a 10-year initial term commencing June 1, 2005, with five 1-year contract renewal options that can be exercised solely by IPCo upon reasonable notice.

6. Respondent's proposal must provide a milestone schedule that identifies key dates including, but not limited to, dates for regulatory approvals, finalization of transmission and interconnection agreements, finalization of fuel supply arrangements, pre-construction milestones, and construction milestones, along with terms for default.

7. Respondent must provide a listing of prior project development and operation activities with project-specific information concerning performance of other projects developed and/or operated by Respondent. A list including names and telephone numbers of persons familiar with Respondent's performance for previous customers would be viewed favorably.

8. Respondent must complete all data requests as defined in Attachments B, C, D, and E.

Portland General Electric Co.

Portland General Electric Co.

REQUEST FOR PROPOSALS

Power Supply Resources

June 18, 2003

Bid Pre-Qualifications

To be considered for evaluation, all proposals must meet the requirements specified below.

General

General pre-qualifications include minimum bid quantity, minimum bid term, credit and bidder qualifications.

Minimum Bid Quantity

The minimum bid amounts are:

- *Non-renewable energy products* – 25 MW/h.
- *Renewable energy products* – 5 MW/h average annual expected output. Proposals for smaller amounts of renewables will be discussed outside of the RFP process.
- *Capacity products* – 25 MW/h.

Minimum Bid Term

The minimum bid terms are:

- *Energy resources* – Five years.
- *Capacity resources* – Two years.

Credit and Bidder Qualifications

All transactions are contingent upon the Bidder meeting and maintaining the credit requirements established by PGE's Wholesale Credit Department:

- Bidder's long-term, senior unsecured debt that is not supported by third-party credit enhancement must be rated BBB- or higher by Standard & Poor's, and Baa3 or higher by Moody's Investor Services, Inc., if the Bidder is rated by both agencies.
- Bidders that are not publicly rated, and bids offering full project ownership, will be subject to review by PGE's Wholesale Credit Department for qualification.

Bidder may obtain credit approval by providing security in a form and amount acceptable to PGE. Bids for an outright purchase of a 100 percent interest in a plant will be considered regardless of the creditworthiness of the Bidder. If the plant is not yet complete, PGE's Wholesale Credit Department requirements will apply until construction is satisfactorily completed. All information required to evaluate and establish credit will be subject to the Confidentiality and Nondisclosure Agreement.

As applicable, the Bidder must provide documentation, satisfactory to PGE, that it is able to schedule power and operate under industry standards established by the Federal Energy Regulatory Commission (FERC), Western Electricity Coordinating Council (WECC) and the North American Energy Reliability Council (NERC).

For Projects Used to Support Bids

Commercial In-Service Date

Projects being developed to support bids must have a reasonable commercial in-service date of no later than January 1, 2008 for energy products, and December 1, 2005, for capacity products. The Bidder must identify the power supply source it intends to use to support its bid commitments before the project in-service date. PGE will consider projects that begin before the specified dates, provided they meet our portfolio needs.

Technology

Projects being developed to support bids shall use commercially viable generation technology. The Bidder shall specify the generation technology it proposes to use and provide preliminary design studies – completed in sufficient detail to identify major equipment. The Bidder will also provide a site layout plan, and a project milestone schedule indicating critical path elements. For generation technologies that are not in common use, the Bidder shall identify electric projects where the technology is already being used or provide documents describing the technology.

Suitability of Site (where applicable)

The Bidder must identify the project site location and provide satisfactory evidence that the site is not otherwise committed and is available for the full-term of the proposed bid. The Bidder must have identified all required site-specific permits and have prepared a plan or schedule for obtaining all permits and licenses.

Fuel Supply (where applicable)

The Bidder must demonstrate physical and commercial access to fuel supplies and fuel transportation for the term of the contract proposed in its bid.

Duke Power

Duke Power
A Duke Energy Company

Request for Proposals

INTRODUCTION

Purpose

Duke Power, a division of Duke Energy Corporation offers this Request for Proposals (RFP) No. 2003-01 for the purpose of acquiring supply-side capacity resources for 2005 and beyond.

Duke Power seeks bid proposals that provide the greatest value to Duke Power and its customers. Value, for the purposes of this solicitation, is the combination of price, reliability, and flexibility. Flexibility includes, but is not limited to, bid proposal structure and physical resource characteristics (delivery scheduling requirements, dispatch capability, etc.). The bid proposals that have greater value to Duke Power may not necessarily be the lowest price proposals. Duke Power reserves the right to modify, suspend, or cancel this RFP.

Eligible Bid Proposals

Duke Power is interested in reliable sources of electric power which provide value to Duke Power and its customers. In that context, Duke Power will consider bid proposals from:

- *Existing Resources:* Existing resources are facilities or systems which are generating electricity as of the date of the bid proposal, except as set forth under Ineligible Bid Proposals below.
- *New Resources:* New resources are facilities which will be completed and meet Duke Power's minimum requirements for reliable capacity prior to proposed delivery of capacity. Bid proposals for New Resources that become part of the short list will be required to submit additional information describing the facility's construction plan and schedule and pre-operation plan.
- *Green/Renewable Resources:* Duke Power is interested in receiving bid proposals for a limited quantity of energy, or capacity and energy, from "green" and/or "renewable" resources. For the purpose of this RFP, eligible green/renewable resources are: Solar (thermal or photovoltaic),

Financial Resources:

- An equivalent corporate bond rating of BBB- or above from at least two rating agencies, one of which should be Moody's or Standard & Poor's. (preferred)
- A commercial paper rating of 1 or 2 from at least two rating agencies, one of which should be Moody's or Standard & Poor's.
- A Dun & Bradstreet credit appraisal rating of 1 or 2.

Additional Proposal Characteristics

Terms and Conditions

Duke Power has included certain Terms and Conditions in the "Model" Power Sales Agreement (PSA) and Collateral Annex of this RFP. By submitting a bid proposal, the respondent agrees that these Terms and Conditions will become part of any agreement reached between Duke Power and the bidder. Should the respondent wish to take exception to any of these Terms and Conditions, the exception must be explained in writing as part of the proposal.

Permits, Licenses, and Approvals

The bidder will be completely and solely responsible for acquiring all licenses, permits, and other regulatory approvals, environmental or otherwise, required by federal, state, or local government laws, regulations, or ordinances for the bid proposal. The bidder will also be completely and solely responsible for ensuring that any implementation of any part of the bid proposal is carried out in full compliance with any changes, modifications, or additions to environmental or other laws, regulations, and ordinances affecting the proposal. Duke Power shall have no responsibility for identifying or securing any license, permits, or regulatory approvals required for the proposal, nor will Duke Power accept any responsibility for securing, locating, or guaranteeing any emissions allowances which may be required by the Title IV Clean Air Act Amendments to allow the implementation of the "Model" transaction or the continuation of the transaction as set forth in the bid proposal.

Tennessee Valley Authority

- Fossil-Fuel Generation
- Hydroelectric Power
- Nuclear Energy
- Transmission
- Our Customers
- Return to Power Main

January 16, 2001

Request for Proposals for Long-Term Base-Load and Summer Peaking Capacity

Reference: Jan2001RFP

Purpose

TVA is seeking proposals from qualified and eligible bidders to meet portions of its base-load and/or summer peaking power supply requirements beginning 2004. TVA is interested in long-term proposals for up to 15 years' duration. TVA prefers proposals with options for early termination and/or options to extend for additional periods, but will consider long-term proposals without options. Proposals for joint ownership with TVA will not be considered. Proposals must offer "firm" capacity from identified generating resources. Bidders may offer to supply base-load and/or summer peaking supply.

This Request for Proposals (RFP) is open to all parties, including, but not limited to: TVA power distributors, independent power producers, exempt wholesale generators, qualifying facilities (under PURPA), power marketers, and utilities.

Description of Capacity Requirements

TVA has a need of up to 600 MW of base-load type capacity (anticipate greater than 40 percent annual capacity factor) and up to 600 MW of summer peaking capacity beginning June 1, 2004. Proposals must be a minimum of 100 MW. Offers of capacity and energy may be from one or more resources. Such resources must be suitable to meet TVA's firm load and/or reserve obligations (i.e., TVA must have first-call priority for shared resources). TVA will not consider proposals that describe non-firm capacity.

Delivery to the TVA System

TVA will only consider offers that deliver capacity and energy to the TVA transmission system. Wheeling and interconnection arrangements and costs to deliver the capacity and energy to the TVA transmission system delivery points are the responsibility of the bidder. Prices quoted must be based upon net capacity delivered to the delivery point. All proposals must identify any wheeling and interconnection agreements with third parties that

Other Terms and Conditions

Proposals must include detailed descriptions of guarantees and related remedies for failure to perform. Each proposal must provide guarantees for in-service dates, contract capacity, heat rates (if applicable to the pricing proposal), and availability. Operational characteristics such as (but not limited to) capacity limitations, ramp limitations, maximum or minimum run-times, maximum or minimum down-times, and fuel limitations should also be specified. If a resource included in a proposal is not yet in-service, a detailed milestone schedule describing major project activities leading up to commencement date for commercial service shall be provided.

Credit Assurance

The bidder will be required to provide certain financial information in order to establish creditworthiness with TVA. Bidders should provide the following information as part of the proposal:

- Audited financial statements for the three (3) preceding years that include balance sheets, income statements, statements of cash flows, and notes to the financial statements.
- Bank name, address, phone number, and officer contact.
- Credit references from three (3) sources that include name, address, phone number, and contact.
- Annual report or company brochure, if available.

TVA requires secure and reliable physical delivery of the capacity and associated energy corresponding to all purchase power agreements. Security and reliability of physical delivery covering both the option and the physical delivery of capacity and energy will be guaranteed by either a:

1. Letter of Credit issued by a financial institution that has a long-term debt rating by Standard & Poor's of A- or better, or by Moody's Investors Service of A3 or better
2. Guarantee issued by an entity that has a long-term debt rating by Standard & Poor's of BBB- or better, or by Moody's Investors Service of Baa3 or better
3. Performance Bond issued by an insurance company or surety that has a long-term debt rating by Standard & Poor's of A- or better, or by Moody's Investors Service of A3 or better, or
4. Various combinations of the foregoing, as determined by TVA.

The cost of such credit assurance must be borne by the bidder.

Reservation of Rights

North Carolina Municipal Power Agency Number 1

(July 2002)

Request for Proposals

ELECTRICITIES

From:

North Carolina Municipal Power Agency Number 1

North Carolina Municipal Power Agency Number 1
Attn: Greg Locke
1427 Meadowwood Blvd.
Raleigh, NC 27604
Telephone: 919-760-6311
Fax: 919-760-6050
Email: glocke@electricities.org

All questions and requests for clarification should be made in writing, preferably by email. NCMPA1, in its sole discretion, will decide whether and how a response will be made.

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3.1 Evaluation Process

The evaluation of proposals will be based on the information provided by the Respondent. A complete response to the information requested in this RFP must be submitted in order for a Respondent's proposal to receive consideration. NCMPA1 reserves the right to negotiate with one or more Respondents to improve their proposals, although selection for negotiation will not be a commitment by NCMPA1 to enter into a contract with any Respondent.

If NCMPA1 decides to accept the submittal of one or more Respondents, it will undertake to negotiate contracts with such Respondents that will embody the general principles and concepts set forth herein. In the event negotiations with a Respondent do not, within a reasonable period of time (as determined by NCMPA1 in its sole judgment), produce a contract satisfactory to NCMPA1, it reserves the right to terminate those negotiations and pursue any and all other options available to it, including, without limitation, entering into negotiations with other parties.

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3.2 Creditworthiness of Respondent

All proposals must provide for the Respondent's obligations to be guaranteed by an entity whose unsecured, senior long-term debt obligations (not supported by third party credit enhancements) or issues rating are rated at least BBB- by Standard & Poor's or Baa3 by Moody's. The Respondent must provide audited financial statements for the past two years for the Respondent and any guarantor.

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3.3 Proposal Content and Submission

Respondents must (i) meet all of the terms and conditions contained in this RFP; (ii) provide the information requested in Attachment 2; and (iii) include all required supporting documentation in order for their proposals to be given consideration by NCMPA1. Multiple offers from a single Respondent, or multiple versions of one proposal, must be submitted as separate proposals, although only one set of audited financial statements needs to be sent if the associated entities are the same.

Two hard copies and an electronic version of all proposals must be submitted and received by NCMPA1 no later than 3:00 PM Eastern Prevailing Time on August 22, 2003. All proposals will become the property of NCMPA1. NCMPA1 retains the right to disqualify any proposal for any reason, whether received on or after the deadline. The Respondent is solely responsible for any and all costs it may incur in responding to this RFP, including those associated with any subsequent negotiations or discussions.

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3.4 Confidentiality

EXHIBIT 5

Requests for Proposals with Market Based Security

Duke Power
A Duke Energy Company

Request for Proposals

INTRODUCTION

Purpose

Duke Power, a division of Duke Energy Corporation offers this Request for Proposals (RFP) No. 2003-01 for the purpose of acquiring supply-side capacity resources for 2005 and beyond.

Duke Power seeks bid proposals that provide the greatest value to Duke Power and its customers. Value, for the purposes of this solicitation, is the combination of price, reliability, and flexibility. Flexibility includes, but is not limited to, bid proposal structure and physical resource characteristics (delivery scheduling requirements, dispatch capability, etc.). The bid proposals that have greater value to Duke Power may not necessarily be the lowest price proposals. Duke Power reserves the right to modify, suspend, or cancel this RFP.

Eligible Bid Proposals

Duke Power is interested in reliable sources of electric power which provide value to Duke Power and its customers. In that context, Duke Power will consider bid proposals from:

- *Existing Resources:* Existing resources are facilities or systems which are generating electricity as of the date of the bid proposal, except as set forth under Ineligible Bid Proposals below.
- *New Resources:* New resources are facilities which will be completed and meet Duke Power's minimum requirements for reliable capacity prior to proposed delivery of capacity. Bid proposals for New Resources that become part of the short list will be required to submit additional information describing the facility's construction plan and schedule and pre-operation plan.
- *Green/Renewable Resources:* Duke Power is interested in receiving bid proposals for a limited quantity of energy, or capacity and energy, from "green" and/or "renewable" resources. For the purpose of this RFP, eligible green/renewable resources are: Solar (thermal or photovoltaic),

“Model”
POWER SALES AGREEMENT

between

[NAME OF SELLER]

and

DUKE POWER,
a division of
DUKE ENERGY CORPORATION
526 South Church Street
Charlotte, North Carolina 28201-1006

[NAME OF FACILITY]

[TERM]

[DATE]

APPENDIX A
TO COLLATERAL ANNEX

CALCULATION OF CURRENT MARK-TO-MARKET VALUE

If the calculation of the Current Mark-to-Market Value as set forth in this Appendix A results in a positive number, then the Current Mark-to-Market Value is positive to Duke Power and negative to Seller. If such calculation results in a negative number, then the Current Mark-to-Market Value is negative to Duke Power and positive to Seller.

Current Mark-to-Market Value = Energy Value plus Capacity Value minus Capacity Payment Value.

Capacity Payment Value = Net Present Value of the Monthly Capacity Payments for each remaining month of the Term.

Capacity Value = Net Present Value of the product of (a) the amounts set forth on Table A-1 for each remaining month of the Term, expressed in $/kw-month, and (b) the Contract Capacity.

The Energy Value shall be the present value of the option value of the Agreement, determined based on the utilization of a daily spark spread option model based on a Black's spread valuation methodology. Unless otherwise mutually agreed by the Parties, the daily spark spread option model shall employ only the following inputs to calculate Energy Value:

Forward Monthly On–Peak Electric Power Prices =

a) For the Quoted Term, the midpoint of the bid-offer spread for the Into Cinergy hub shall be used.

b) Beyond the Quoted Term, the Forward Monthly On-Peak Electric Power Prices shall be the previous year's price for that month, escalated by 3% per year.

Forward Daily Gas Volatility =

a) For the period up to twelve months from the Calculation Date, the Forward Daily Gas Volatility shall be the implied volatility for At-The-Money (ATM) options exercised daily, calculated based on the midpoint of the bid-offer spread.

b) For the period after twelve months from the Calculation Date, the Forward Daily Gas Volatility shall be as set forth in Table A-2, except that to the extent readily observable market prices for ATM options as described in (a) above are available, the method described in (a) above shall be used for this period also.

Forward Daily Power Volatility	=	a) For the period up to twelve months from the Calculation Date, the Forward Daily Power Volatility shall be the implied volatility for At-The-Money (ATM) options exercised daily, calculated based on the midpoint of the bid-offer spread. b) For the period after twenty-four months from the Calculation Date, the Forward Daily Power Volatility shall be as set forth in Table A-2. c) For each day throughout the period beginning with the thirteenth month and ending with the twenty-fourth month from the Calculation Date, the Forward Daily Power Volatility shall be the average of the Forward Daily Power Volatilities on the equivalent day in the periods set forth in "a" and "b", above, except that to the extent readily observable market prices for ATM options as described in (a) above are available, the method described in (a) above shall be used for this period also.
Forward Correlation of Power and Gas	=	The initial value of this input will be ____ and will remain constant. Either Party may request changes to this value based on historical information. If such change is agreed to, the newly agreed value will be utilized in subsequent calculations of the Energy Value.
Forward Time to Expiry	=	Time to expiry shall be expressed in calendar days (as opposed to business days) utilizing a mid-month convention for calculating time to expiry.
Forward Strike Price	=	The forward strike price in the daily option value calculation shall be the sum of the Base VOMP n $/MWh) and the Start Cost (expressed in $/MWh). Start Cost ($/MWh) = Start Cost (in dollars per start) / (Contract Capacity x 16 hours).

Forward Natural Gas Prices	=	a) for each day throughout the Quoted Term, the Forward Natural Gas Price for each such day shall be the closing price for the NYMEX natural gas contract (Henry Hub) for the last trading day preceding the Calculation Date, plus a basis of $____ per MMBtu. b) for periods beyond the Quoted Term, the Forward Natural Gas Price shall be the the previous year's price for that month, escalated by 3% per year.
Heat Rate	=	The expected heat rate of the Designated Capacity Resource operating under expected summer conditions. The parties agree that, prior to the commencement of the Term, the Heat Rate shall be equal to _____ Mmbtu per KWH for purposes of this calculation.

To the extent the either of the reference pricing points (NYMEX and Henry Hub for gas; Into-Cinergy for power) cease to be available or actively traded, a replacement hub or other observable price point may be used as mutually agreed to by both Parties, with appropriate basis adjustments.

Table A-1

Monthly capacity value - $/Kw/mo

	2004	2005	2006	2007	2008
Jan					
Feb					
Mar					
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					

Table A-2

Months from Calculation Date	Gas Volatility %	Power Volatility %
13-24		
Summer		
Winter		
25-36		
Summer		
Winter		
37-48		
Summer		
Winter		
49-60		
Summer		
Winter		
61-72		
Summer		
Winter		
73-84		
Summer		
Winter		
>= 85		
Summer		
Winter		

Summer – June, July and August
Winter – January through May, and September through December

Entergy

Spring 2003
Request for Proposals (RFP)
for
Supply-Side Resources

Entergy Services, Inc.
April 18, 2003

The statements contained in this RFP are made subject to the Reservation of Rights set forth in this RFP and subject to the terms and acknowledgements set forth in the Proposal Submission Agreement.

Figure G5

Credit Evaluation - Illustration of Calculation of Performance Risk Exposure

Calculate potential replacement power risk using methodology from Figure G3:

Where:

P_t	=	All-in bid price in \$/MWh
CF	=	Expected Capacity Factor
EC	=	Energy Charge in \$/MWh
EXP_t	=	Exposure per year in \$/yr
V	=	Volume in MW
TRE	=	Total Remaining Exposure in \$'s
r	=	ESI's cost of capital
t	=	Contract Year
T	=	Number of Contract Years in proposal
$IFP_{t,c}$	=	Indicative Forward Price Curve in \$/MWh, by contract type
CC_t	=	Capacity Charge in \$/kW-yr

TRE = SUM(t=1 to T) {(EXP_t/(1+r)^(t-0.5)} = \$

EXP_t = ($IFP_{t,c} - P_t$) x V x CF x 8760hr/yr = \$/yr

$IFP_{t,c}$ depends on proposal type

$IFP_{t,c}$ for a fixed price contract is derived from a forward market quote of a similar product in the traded market. The $IFP_{t,c}$ is the implied heat rate of the forward traded market plus one standard deviation of the forward fuel gas volatility.

$IFP_{t,c}$ for a guaranteed heat rate at indexed gas price is derived from the implied heat rate of the all-in-price of the proposal plus one standard deviation of the forward heat rate volatility.

$$P_t = EC + (CC_t / CF \times 1000kW/MW)/8760hr/yr = \$/MWh$$

Example (All numbers are only illustrative):

Product: 3 year Multiple-Year Unit Capacity Purchase Agreement (MUCPA) for CCGT from bidder XYZ

Offer Size in Proposal: 200 MW

Expected Capacity Factor: 67%

Price Bid in Proposal: Capacity–$36.00 per kW-year for each year of the contract
Energy–$30.00 per MWh

Indicative Forward Price Curve price (see below): $48/MWh (t=1), $44/MWh (t=2), $40/MWh (t=3)

ESI's cost of capital, r = 8%

Supplier Evaluated Credit Rating: BBB-

Calculation of Incremental Supplier Risk:

$$P_{t=1,2,3} = EC + (CC_t/CF \times 1000kW/MW)/8760hr/yr = \$/MWh$$

$$P_{t=1,2,3} = \$30 + (\$36/67\% \times 1000kW/MW)/(8760hr/yr) = \$36.13$$

$$EXP_t = (IFP_t - P_t) \times V \times CF \times 8760hr/yr = \$/yr$$

$$EXP_{t=1} = (\$48 - \$36.13) \times 200MW \times 67\% \times 8760hr/yr = \$13.9MM/yr$$
$$EXP_{t=2} = (\$44 - \$36.13) \times 200MW \times 67\% \times 8760hr/yr = \$\ 9.2MM/yr$$
$$EXP_{t=3} = (\$40 - \$36.13) \times 200MW \times 67\% \times 8760hr/yr = \$\ 4.5MM/yr$$

$$TRE = SUM(t=1 \text{ to } T)\ \{(EXP_t/(1+r)^\wedge(t-0.5)\} = \$$$

$$TRE = (\$13.9MM/(1+8\%)^\wedge(1-0.5) + \\ + (\$9.2MM/(1+8\%)^\wedge(2-0.5) + \\ + (\$4.5MM/(1+8\%)^\wedge(3-0.5) = \$25.4MM$$

However, pre-existing transactions between bidder XYZ and another Entergy Operating Company unit have current un-collateralized exposure of $30MM. Hence, overall exposure with bidder XYZ is calculated:

TRE_{XYZ} = \$24.4MM + \$30MM = \$55.4MM

From Figure G4 maximum un-collateralized exposure for BBB- entity = \$50MM

Additional Collateral remediation necessary in year one = \$55.4MM - \$50MM = \$5.4MM

In the first review after the start of delivery of energy pursuant to the contract, the exposure amount would be lowered by an amount equal to 45 days of accounts receivable due from ESI.

Capacity payment:
1.5 months * \$36/kW/yr / 12 months/year * 200 MW = \$ 0.9 MM
Energy payment:
1.5 months * \$36.13/MWh * 200 MW * 67% * 744 hr/mo = \$ 5.3 MM

Indicative Forward Price Curves:

The Indicative Forward Price Curve for comparison to a fixed price proposal is derived from the implied heat rate of a forward quote of a similar traded product, multiplied by the forward fuel (gas) volatility. If the 5x16 is quoted on average of a heat rate of 8,400 Btu/kWh, and the forward fuel volatility is 23%, the heat rate of the Indicative Forward Price Curve would be 10,332 Btu/kWh, or priced at \$48/MWh, with gas at \$4.63/mmBtu.

The Indicative Forward Price Curve for comparison to a proposal with guaranteed heat rate and indexed fuel price is derived from the implied heat rate of the proposal's all-in-price, multiplied by the forward heat rate volatility. If the above proposal had been quoted as an indexed proposal, the implied heat rate would be 7,812 at \$4.63/mmBtu fuel cost; a forward heat rate volatility of 17% would create an Indicative Forward Price at 9,140 Btu/kWh or \$42.28/MWh.

The exposure calculation will be adjusted periodically to reflect market movements. The difference in heat rate for a similar product between 4/30/03 and the date of the adjustment will be added to the implied heat rate. For example, if the implied market heat rate for a 5x16 product moved from 8,400 to 8,600 Btu/kWh, the proposal would be evaluated with an Indicative Forward Price Curve derived from [7,812 + (8,600-8,400)] = 8,012 Btu/kWh, multiplied with the appropriate forward volatility.

Note: Collateral requirements are adjusted to accommodate change in Indicative Forward Price Curve (IFP) as well as attenuation of time remaining in contract. The Indicative Forward Price Curve will be updated periodically for proposals awarded through the RFP process.

EXHIBIT 6

Requests for Proposals with Comparable Performance Security

Cheyenne Light, Fuel and Power Company

Request for Proposals

System Firm, Full Requirements Supply-Side Resource

December 2002

Xcel Energy[SM]
CHEYENNE LIGHT

Proposals must meet the requirements set forth above. Proposals for financially firm capacity and energy, unit contingent capacity and energy (except as a component of a system firm, full requirements package), or partial requirements capacity and energy **will not** be accepted. Bidders may propose constructing new generating resources or new transmission facility interconnections as components of a full requirements proposal which meets the requirements set forth above. Bidders are encouraged to identify and describe that portion of the resource portfolio proposed to serve CLF&P's capacity and energy requirements which qualifies as renewable or "green" power resources.

Table 1 provides historical and forecasted CLF&P total capacity and energy requirements on an annual basis for the period 2001-2018, as well as historical CLF&P total capacity and energy requirements on a monthly basis for calendar year 2001.

TABLE 1
CLF&P Annual Capacity and Energy Requirements

YEAR	ANNUAL PEAK DEMAND (MW)*	ANNUAL ENERGY (GWh)*	ANNUAL LOAD FACTOR
2001	146	970	76%
2002	152	1,012	76%
2003	156	1,048	77%
2004	158	1,066	77%
2005	159	1,083	78%
2006	164	1,103	77%
2007	165	1,115	77%
2008	168	1,131	77%
2009	168	1,148	78%
2010	171	1,166	78%
2011	172	1,182	78%
2012	175	1,203	78%
2013	177	1,222	79%
2014	179	1,240	79%
2015	181	1,256	79%
2016	183	1,273	79%
2017	185	1,288	80%
2018	187	1,301	80%

The information provided in each bid will be evaluated for completeness and consistency with the filing requirements specified in this RFP. CLF&P reserves the right to either (1) reject incomplete or unclear bids from further consideration or (2) contact bidders for purposes of clarifying proposal terms or requesting additional information. Given the short amount of time allotted to evaluate the bids, CLF&P will limit these follow-up contacts to only those bids that best meet the desired bid characteristics (see "Desired Bid Characteristics" above). All bids that pass the initial screening evaluation steps will be considered for final cost analysis. The proposal finally selected for negotiation will be the proposal that meets the identified need at low cost and low risk to CLF&P customers.

3.3 NOTIFICATION OF BID RESULTS

It is CLF&P's intent to notify bidders of the results of the evaluation of their proposals and begin contract negotiations on or about March 28th 2003. The resulting PPA should be fully negotiated and executed within 60 days of shortlist notification. Failure to execute the PPA within such timeframe may result in the primary bid being replaced with an alternate bid for negotiation and execution of a PPA.

4. POWER PURCHASE AGREEMENT (PPA)

CLF&P is under no obligation to negotiate from, or enter into a final PPA with the bidder/supplier based on, any PPA form proposed by the shortlisted bidder, and discourages bidders from submitting any such PPA form. CLF&P intends to develop, and provide to the shortlisted bidder, the initial draft of the PPA, based on the shortlisted bidders proposal, and negotiate with the shortlisted bidder from such initial draft. The following will be a part of the final PPA.

- Depending upon the creditworthiness of the Seller, Seller may be required to post up to $22,000,000, in a form acceptable to CLF&P, as security for Seller's performance under the PPA.
- Default and remedy provisions that specifically state that if Seller is the defaulting party, the damages recoverable by CLF&P on account of such default by Seller shall include, but not be limited to, CLF&P's costs to replace that capacity and energy which Seller failed to deliver, less the sum of any payments from CLF&P to Seller which were eliminated as a result of such failure.
- Seller will be required to adhere to applicable NERC and WECC (or successor organizations) standards and requirements.
- Seller will be responsible for all taxes, including all income taxes, sales taxes, property taxes, energy tax credits, energy taxes, emissions credits, emissions taxes, tariffs, import

NORTHERN STATES POWER COMPANY

MODEL POWER PURCHASE AGREEMENT

These model terms are designed to provide bidders with guidance on specific terms and general concepts that will be important in evaluating resource bids from newly constructed generation facilities and establishing the associated power purchase agreement (PPA). The contract terms applicable to a successful bid will be contained in the final PPA with the successful bidder. Terms or concepts in the model PPA that are not applicable to a successful bid will be eliminated.

Please note that these model terms are intended to apply to a wide variety of bids, but only to the extent that they are applicable to such bids. (This model PPA assumes new construction with NSP purchasing the entire planned capacity output from the new facility.) Bids with different transaction configurations will be considered. (The model recognizes some variation in pricing and other terms, depending on the specific characteristics of the bid.) Bidders should provide specific exceptions to any applicable model term the bidder does not want to accept. The exception should include a price impact on the bid if the exception is rejected by NSP. Bidders are strongly encouraged to minimize the number and magnitude of exceptions to applicable model PPA terms and conditions.

generation of energy at the Facility or any similar program pursuant to any federal, state or local legislation or regulation. *[Applicable primarily to renewable and variable energy resource proposals.]*

Article 11 - Security for Performance

11.1 Security Fund.

(A) Seller shall establish, fund, and maintain a Security Fund, pursuant to the provisions of this Article 11, which shall be available to pay any amount due NSP pursuant to this PPA, and to provide NSP security that Seller will construct the Facility to meet the Construction Milestones. The Security Fund shall also provide security to NSP to cover damages, including but not limited to Replacement Power Costs, should the Facility fail to achieve the Commercial Operation Date or otherwise not operate in accordance with this PPA. Seller shall establish the Security Fund at a level of $*[$100/kW of Net Capability, reduced level may apply to variable energy resource proposals]* no later than *[date no later than 2 months after execution of the PPA]*, and shall maintain the Security Fund at such required level throughout the remainder of the Term. Seller shall replenish the Security Fund to such required level within fifteen (15) Business Days after any draw on the Security Fund by NSP.

(B) In addition to any other remedy available to it, NSP may, before or after termination of this PPA, draw from the Security Fund such amounts as are necessary to recover amounts owing to it pursuant to this PPA, including, without limitation, any damages due to NSP and any amounts for which NSP is entitled to indemnification under this PPA. NSP may, in its sole discretion, draw all or any part of such amounts due to it from any form of security to the extent available pursuant to this Section 11.1, and from all such forms, and in any sequence NSP may select. Any failure to draw upon the Security Fund or other security for any damages or other amounts due to NSP shall not prejudice NSP's rights to recover such damages or amounts in any other manner.

(C) The Security Fund shall be maintained at Seller's expense, shall be originated by or deposited in a financial institution or company ("Issuer") acceptable to NSP, and shall be in the form of one or more of the following instruments. Seller may change the form of the Security Fund at any time and from time to time upon reasonable prior notice to NSP, but the Security Fund must at all times be comprised of one or any combination of the following:

(1) An irrevocable standby letter of credit or a performance bond, in form and substance acceptable to NSP, from an Issuer with an unsecured bond rating equivalent to A- or better as determined by at least two (2) rating agencies, one of which must be either Standard & Poor's or Moody's (or if either one or both are not available, equivalent ratings from alternate rating sources acceptable to NSP). Security provided in this form shall be consistent with this PPA and include a provision for at least thirty (30) Days advance notice to NSP of any expiration or earlier

termination of the security so as to allow NSP sufficient time to exercise its rights under said security if Seller fails to extend or replace the security. The form of such security must meet NSP's requirements to ensure that claims or draw-downs can be made unilaterally by NSP in accordance with the terms of this PPA. Such security must be issued for a minimum term of three hundred and sixty (360) Days. Seller shall cause the renewal or extension of the security for additional consecutive terms of three hundred and sixty (360) Days or more (or, if shorter, the remainder of the Term of this PPA) no later than thirty (30) Days prior to each expiration date of the security. If the security is not renewed or extended as required herein, NSP shall have the right to draw immediately upon the security and to place the amounts so drawn, at Seller's cost and with Seller's funds, in an interest bearing escrow account in accordance with subparagraph (2) below, until and unless Seller provides a substitute form of such security meeting the requirements of this Article. Security in the form of an irrevocable standby letter of credit shall be governed by the Uniform Customs and Practice for Documentary Credits (1993 Revision), International Chamber of Commerce Brochure No. 500.

(2) United States currency, deposited with Issuer, either: (i) in an account under which NSP is designated as beneficiary with sole authority to draft from the account or otherwise access the security; or (ii) held by Issuer as escrow agent with instructions to pay claims made by NSP pursuant to this PPA, such instructions to be in a form satisfactory to NSP. Security provided in this form shall include a requirement for immediate notice to NSP from Issuer and Seller in the event that the sums held as security in the account or trust do not at any time meet the required level for the Security Fund as set forth in this Section 11.1. Funds held in the account may be deposited in a money-market fund, short-term treasury obligations, investment-grade commercial paper and other liquid investment-grade investments with maturities of three months or less, with all investment income thereon to be taxable to, and to accrue for the benefit of, Seller. After the Commercial Operation Date is achieved, annual account sweeps for recovery of interest earned by the Security Fund shall be allowed by Seller. At such times as the balance in the escrow account exceeds the amount of Seller's obligation to provide security hereunder, NSP shall remit to Seller on demand any excess in the escrow account above Seller's obligations.

(3) A guarantee, in form and substance satisfactory to NSP, from an Issuer with an unsecured bond rating equivalent to BBB+ or better as determined by at least two (2) rating agencies, one of which must be either Standard & Poor's or Moody's (or if either one or both are not available, equivalent ratings from alternate rating sources acceptable to NSP).

(D) NSP may reevaluate from time to time the value of all non-cash security posted by Seller for possible downgrade or for other negative circumstances. If either (i) the unsecured bond rating (as determined by either Standard & Poor's or Moody's, or if neither is available, an equivalent rating from an alternate rating source acceptable to NSP) of the Issuer falls below the equivalent of BBB+, or (ii) if such unsecured bond rating of the Issuer is exactly the equivalent of BBB+ and the Issuer is placed on credit watch by a rating agency, then Seller shall be required to convert the Security Fund instrument provided by such Issuer to an irrevocable standby letter of credit meeting the criteria set forth in Section 11.1(C)(1), within thirty (30) Days of such rating action.

(E) Promptly following the end of the Term and the completion of all of Seller's obligations under this PPA, NSP shall release the Security Fund (including any accumulated interest, if applicable) to Seller.

(F) Seller shall reimburse NSP for the incremental direct expenses (including, without limitation, the reasonable fees and expenses of counsel) incurred by NSP in connection with the preparation, negotiation, execution and/or release of any security instruments, and other related documents, used by Seller to establish and maintain the Security Fund pursuant to Seller's obligations under this Section 11.1.

11.2 Additional Security.

(A) Prior to the Commercial Operation Date, Seller and/or NSP, as the case may be, shall execute and record, as appropriate, separate agreements, documents, or instruments under which Seller will provide NSP, in a form reasonably acceptable to NSP and the Facility Lender, with fully perfected subordinated security interest(s), and/or mortgage lien (collectively the "Subordinated Mortgage") in the Facility and in any and all real and personal property rights, contractual rights, or other rights that Seller acquires in order to construct and/or operate the Facility. The Subordinated Mortgage shall be given to secure Seller's continuing performance and any amounts that may be owed by Seller to NSP pursuant to this PPA, including, without limitation, any damages excluded from the limitation on Seller's liability for the limited purposes set forth in Section 12.6(A) through (E). Seller agrees, and shall cause the Facility Lender to agree and the Financing Documents to provide, (i) that such Subordinated Mortgage shall be subordinate in right of payment, priority, and remedies only to the interests of the Facility Lender, and (ii) that, as long as NSP is not in material default of its obligations under this PPA, the Facility and any party taking possession of the Facility through the exercise of the Facility Lender's rights and remedies shall remain subject to the terms of this PPA and the assumption of Seller's obligations hereunder. The collateral secured by the Subordinated Mortgage shall not include the pledge, assignment, or other interest in any stock or ownership interest in Seller; provided that Seller shall not pledge or assign, or cause or permit to be pledged or assigned, any stock or ownership interest in Seller as collateral to any party other than the Facility Lender without the prior consent of NSP.

(B) NSP agrees to cooperate with Seller and diligently negotiate in good faith, at Seller's request, to establish the form of these agreements and to execute and deliver such agreements as reasonably necessary to enable Seller to meet the Construction Milestones. The Parties shall confirm, define, and perfect such Subordinated Mortgage by executing, filing, and recording, at the expense of Seller, the Subordinated Mortgage. In addition, Seller agrees to execute and file such Uniform

1999
Integrated
Resource
Plan

Final
Request for Proposals

Supply-Side Resources

January 28, 2000

PUBLIC SERVICE
COMPANY OF COLORADO

APPENDIX C
MODEL CONTRACT

(A) PSCo and Seller shall each appoint one representative and one alternate representative to act in matters relating to the operation of the Facility and PSCo's system under this PPA and to develop detailed operating arrangements for delivery of power from the Facility to PSCo. Such representatives shall constitute the Operating Committee. The Parties shall notify each other in writing of such appointments and any changes thereto. The Operating Committee shall have no authority to modify the terms or conditions of this PPA.

(B) The Operating Committee shall develop mutually agreeable written Operating Procedures by __________. The Operating Procedures will be intended as a guide on how to integrate the Facility and its electrical output into PSCo's system and shall be consistent with the provisions of this PPA. Operating Procedures shall include, but not be limited to, method of day-to-day communications; metering, telemetering, telecommunications, and data acquisition procedures; key personnel list for applicable PSCo and Seller operating centers; clearances and switching practices; operating and maintenance scheduling and reporting; daily capacity and energy reports; unit operations log; reactive power support; and such other matters as may be mutually agreed upon by the Parties.

Article 11 - Security for Performance and Damages

11.1 <u>Security for Performance</u>.

(A) Seller shall establish, fund, and maintain a Security Fund which shall be available at PSCo's discretion pursuant to Section 11.2 to pay any amount due PSCo pursuant to this PPA, and to provide PSCo security that Seller will construct the Facility to meet the Construction Milestones and the Commercial Operation Date. The Security Fund shall provide security to PSCo to cover Replacement Power Costs should the Facility not operate in accordance with this PPA. Seller agrees to establish a Security Fund no later than 30 days after the execution of this PPA and to maintain the Security Fund at the required level throughout the term of this PPA. Seller shall establish and maintain a security fund at a level of $______________ ($100/kW of Net Capability).

(B) The Security Fund shall be maintained at Seller's expense, shall be originated by or deposited in a financial institution or company ("Issuer") acceptable to PSCo, and shall be in the form of one or more of the following instruments, to be determined by mutual agreement of PSCo and Seller and specified in Exhibit I to this PPA:

(1) An irrevocable standby letter of credit or a performance bond in form and substance acceptable to PSCo and consistent with this PPA, including a provision for thirty (30) days advance notice to PSCo of any expiration of the security so as to allow PSCo sufficient time to exercise its rights under said security if Seller fails to extend or replace the security; or

(2) United States currency, deposited with Issuer, either: (i) in an account under which PSCo is designated as beneficiary with authority to draft from the account of the Issuer or otherwise access the security; or (ii) held by Issuer as trustee with instructions to pay claims made by PSCo pursuant to this PPA, such instructions to be in a form satisfactory to PSCo. Security provided in this form shall include a requirement for immediate notice to PSCo from Issuer and Seller in the event that the sums held as security in the account or trust do not at any time meet the minimum security requirements as set forth in this Article 11. After Commercial Operation is achieved, annual account sweeps for recovery of interest earned by the Security Fund will be allowed if Seller is not in default; or

(3) In PSCo's sole discretion, a guarantee, in form and substance satisfactory to PSCo, from an entity with a bond rating of BBB+ or better as determined by at least two (2) rating agencies, one of which must be either Standard & Poor's or Moody's (or if either one or both are not available, ratings from alternate rating sources selected by PSCo). In addition, the entity providing such guarantee cannot be on credit watch or show a negative ratings trend.

(C) PSCo will reevaluate on an annual basis the value of all non-cash security posted by Seller. If the rating (as measured by either Standard & Poor's or Moody's, or if neither is available, a rating from an alternate rating source selected by PSCo) of the entity guaranteeing the security falls below BBB+ or if such entity is placed on credit watch by a rating agency, Seller shall be required to convert the security provided by the guarantee to an irrevocable standby letter of credit from an Issuer within thirty (30) days of such rating action.

(D) If security in the form of an irrevocable standby letter of credit is utilized by Seller to fund the Security Fund, the form of such letter must meet PSCo's requirements to ensure that claims or draw-downs can be made in accordance with the terms of this PPA. Such security must be issued for a minimum term of one (1) year. The security must be renewed or extended for another one (1) year term no later than thirty (30) days prior to its expiration date. If Seller fails to renew such security as required under this Article, PSCo shall have the right to draw immediately upon the security and to place the amounts so drawn in an escrow account in accordance with this Article until and unless Seller shall provide a substitute form of such security meeting the requirements of this Article.

(E) With respect to any escrow account opened as security for Seller's obligations hereunder, PSCo shall establish at Seller's cost and with Seller's funds an interest-bearing escrow account in the name of PSCo. Such escrow account may be drawn upon by PSCo to satisfy any unsatisfied obligations hereunder that it is intended to secure. If Seller's obligation to provide security hereunder expires, PSCo shall, within a reasonable period of time, return the balance in such escrow account to Seller. At such times as the balance in the escrow account exceeds the amount of Seller's obligation to provide security hereunder, PSCo shall remit, within a reasonable period of time, to Seller any excess in the escrow account above Seller's obligations. Seller may obtain the return of such escrow account at any time by providing to PSCo a substitute form of security in the same amount as the escrow account and meeting the appropriate criteria specified in this Article.

11.2 Damages.

(A) Delay Damages. If Seller fails to meet any Construction Milestone set forth on Exhibit B, subject to extension for Force Majeure or delay attributable to PSCo under Section 14.4, Seller shall pay Delay Damages to PSCo as specified below. PSCo will invoice Seller for Delay Damages. If the invoice is not paid in 30 days, PSCo may withdraw funds from the Security Fund, as specified below:

Event	Delay Damages
Failure to meet the Construction Milestone set forth on Exhibit B, except for Commercial Operation Milestone Date	\$5 per MW of Net Capability per day
Failure to achieve the Commercial Operation Milestone Date set forth on Exhibit B	\$200 per MW of Net Capability per day during On-Peak Months
	\$100 per MW of Net Capability per day during months other than On-Peak Months

All Delay Damages shall begin accruing the day after the Construction Milestone or the Commercial Operation Milestone Date, as applicable, and shall continue until the specific milestone and/or Commercial Operation Date is achieved. All Delay Damages shall be cumulative, but shall not exceed the amount required to be contributed to the security fund pursuant to Section 11.1. If Seller achieves the Commercial Operation Date set forth on Exhibit B, all Delay Damages paid by Seller to PSCo, less any amounts incurred by PSCo under Section 12.5, shall be refunded to Seller, without interest, at the first monthly billing cycle following the Commercial Operation Date.

(B) Damages for Termination. In addition to other remedies available to PSCo under this PPA and in law or equity for Seller's breach if there is an Event of Default of Seller under Article 12, PSCo may immediately draw down the entire amount of the Security Fund as security for damages due as a result of Seller's

EXHIBIT 7

List of FPL Contracts with Regulatory Modification Provisions

Florida Power & Light Company
Purchased Power Agreements With
Regulatory Modifications Provisions

1) Bio-Energy Partners

2) Florida Crushed Stone Company

3) SES Broward Company, Limited Partnership - 1987 Agreement

4) Broward Waste Energy Company, Limited Partnership - 1987 Agreement

5) Palm Beach County Solid Waste Authority

6) Cedar Bay Generating Company Limited Partnership

7) Indiantown Cogeneration L.P.

8) Wheelbrator South Broward Inc. -1991 Agreement

9) Wheelbrator North Broward Inc -1991 Agreement

EXHIBIT 8

Spring/Summer 2001 FPL Transmission Interconnection Queue

QUEUE / PRIORITY OF REQUEST FOR GENERATION INTERCONNECTIONS

Queue Status	General location of Interconnection	Project Capacity/ Addition (MW)	Date Project Established in Queue	General Comments
1	Ft. Myers Sub[1]	1102	4/1/1999	None
2	Martin Sub[1]	896	4/1/1999	None
3	Sanford Sub[1]	1356	4/12/1999	None
4	Hypoluxo Sub	238	11/8/1999	None
5	Ft. Myers Sub[1]	362	12/16/1999	None
6	Martin Sub[1]	362	12/16/1999	None
7	Brevard Sub[1]	796	1/4/2000	None
8	Sherman Sub	586	2/5/2000	None
9	Buckeye Sub	530	2/28/2000	None
10	Midway Sub	1214	3/13/2000	None
11	Midway Sub[1]	1360	3/21/2000	None
12	Midway Sub	650	3/27/2000	None
13	Whidden Sub	471	3/29/2000	None
14	Turkey Point Sub [1]	724	3/20/2000	None
15	Martin Sub [1]	362	3/30/2000	None
16	Midway Sub	366	4/21/2000	None
17	Turkey Point Sub	366	4/21/2000	None

[1] Project has been designated as a Network Resource or a valid request has been submitted for Long-Term Firm Point-to-Point Transmission Service for the full or partial output of the project.

18	Broward Sub	366	4/21/2000	None
19	Corbett Sub	399	4/27/2000	None
20	Broward Sub	640	5/15/2000	None
21	Corbett Sub	270	5/15/2000	None
22	Pennsuco Sub	366	6/2/2000	None
23	Midway Sub	241	8/17/2000	None
24	Buckeye Sub	241	8/17/2000	None
25	Midway Sub	213	9/14/2000	None
26	Broward Sub	213	9/14/2000	None
27	Broward Sub	581	9/14/2000	None
28	Broward Sub	281	9/20/2000	None
29	Broward Sub	281	9/20/2000	None
30	Midway Sub	281	9/20/2000	None
31	Corbett Sub	474	9/20/2000	None
32	Midway Sub [1]	362	10/5/2000	None
33	Emerson Sub	213	10/11/2000	None
34	Orange River Sub	1764	12/08/2000	None
35	Midway Sub	560	12/12/2000	None
36	Ft Myers Sub[1]	245	12/18/2000	None
37	Martin Sub[1]	245	12/18/2000	None
38	Buckeye Sub	810	1/11/2001	None
39	Johnson Sub	12	1/12/2001	None
40	Turkey Point Sub	213	1/16/2001	None
41	Turkey Point Sub	281	1/16/2001	None
42	Midway Sub	241	2/13/2001	None
43	Mims Sub	12	3/5/2001	None
44	Midway Sub[1]	245	3/15/2001	None

[1] Project has been designated as a Network Resource or a valid request has been submitted for Long-Term Firm Point-to-Point Transmission Service for the full or partial output of the project.

45	Martin Sub[1]	159	3/16/2001	None
46	Martin Sub[1]	159	3/16/2001	None
47	Buckeye Sub	543	4/2/2001	None

Revised on 4/5/2001

[1] Project has been designated as a Network Resource or a valid request has been submitted for Long-Term Firm Point-to-Point Transmission Service for the full or partial output of the project.

EXHIBIT 9

General Information Regarding FPL's Transmission System Capability, November 2002

General Information Regarding FPL's Transmission System Capability

Generator Interconnection Service ("GIS") And Long-Term Firm Transmission Service ("LTFTS")

Overview

- The intent of the document is to provide general information as to the capability of the FPL transmission system with respect to the provision of Generator Interconnection Service ("GIS") or Long-Term Firm Transmission Service ("LTFTS"). The information provided in this document takes into consideration all long-term firm obligations and commitments. The impacts associated with a specific request for GIS or LTFTS may differ substantially from the general information provided in this document. As such, while this information may serve as a preliminary aid to a generator developer or an entity requesting transmission service, the final determination of the impact of such request for GIS or LTFTS is based on the studies associated with such request, where such request lies within the respective Queue and the specifics associated with such requests.

Assumptions

- Previously performed GIS and LTFTS studies along with FPL's general knowledge and experience of the FPL transmission system.
- The information provided in this document takes into consideration all long-term firm obligations.

Information limitations:

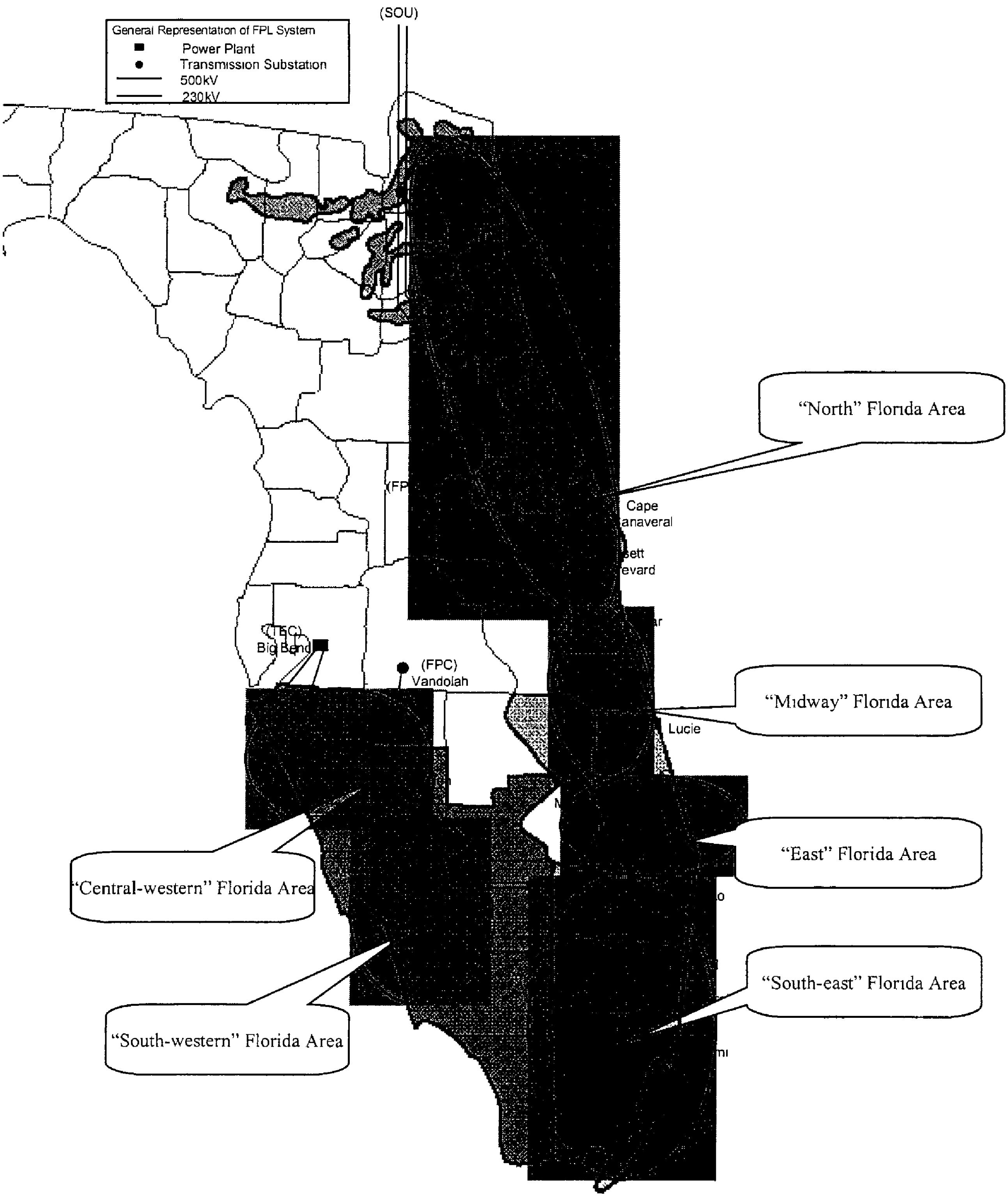
- This document is only intended to provide general information and serve for preliminary due diligence work by the generator developer prior to requesting generation interconnection service and/or transmission service for a new generator. It is not intended to provide specific and accurate results for any particular new generation project.
- This document does not take into consideration other important factors to a generator such as water, fuel and the environment.
- This document is not specific to the areas/sites discussed. Distinct generation points of connection in close proximity may provide results different than the information provided in this document.

FPL does not make any representation regarding the information provided in this document. Entities interested in requesting an interconnection of generator or transmission service should regard this information as preliminary, generic, non-specific and subject to change, and as such should perform their own evaluations as part of their initial due diligence. Moreover, by providing this information FPL is not offering to purchase the output of any generation requesting GIS or LTFTS, nor does FPL warrant or otherwise guarantee the availability of Firm Transmission Service.

In order to determine the impact of a specific request for GIS or LTFTS an entity must request such service in accordance with FPL's Open Access Transmission Tariff and FERC Policy. The impact of a request for GIS or LTFTS may be dependent on a preceding request for GIS or LTFTS. Additionally, the information provided may become invalid as a result of requests for GIS or LTFTS being confirmed. Specifically, interconnection and transmission service requests change frequently and such changes can affect the results of any study at a particular location. Accordingly, reference should be made to FPL's OASIS for information to existing requests at or near a particular location. As such the information provided in this document is subject to change as a result of preceding requests for GIS or LTFTS that come to fruition and/or planned and unplanned changes in system conditions.

FPL may unilaterally update the information in this document at FPL's discretion.

Transmission Interconnection & Integration



General Area (Geographic and /or Substation)	Point of Connection Voltage	System Impact
Midway Area	500 kV	GIS: Generally favorable for GIS. Impact on short circuit levels on the 230 kV system may require the replacement of multiple breakers and various sections of Overhead Ground Wire ("OHGW") in this area and/or the installation of 230 kV phase Reactors at Martin substation (south of Midway). LTFTS: Within the Midway Area LTFTS availability is dependent on the impact on 230 kV transmission facilities South from Midway. Requests greater than 1200MW of LTFTS may require the upgrade or the construction of new 230 kV lines south of Midway to the area of Ranch substation which are of extended lengths requiring long lead times due to extensive construction and clearance availability. Limited right-of-way will also extend project lead times. Northward LTFTS in the amounts of 500-900 MW are generally favorable and potentially accommodated without major upgrades/new facilities. Note: The amount of total generation connected to Midway Substation is limited to approximately 3600MW taking into consideration a potential catastrophic event (e.g., the loss of the site and/or attendant transmission corridors), which event results in unacceptable system performance.
Midway Area	230 kV	GIS: Marginal capability is available due to impact on short circuit levels. The 230 kV system will first require the replacement of multiple breakers in this area and various sections of OHGW. Amounts in excess of 300 MW of new generation may require the installation of 230 kV phase reactors at Martin substation (south of Midway). Amounts in excess of 800+ MW may require the splitting of the Midway Substation and/or the installation of reactors at Martin substation (South of Midway. Both installations require long lead times due to clearance availability. System stability is also of concern in this area. Critical clearing times are marginal and the addition of sizable amounts of new generation may require system reconfiguration and/or facility modifications. Also, work at or in the vicinity of Midway substation requiring clearances may need to be coordinated with an outage of St. Lucie nuclear power plant which is connected to Midway substation.

General Area (Geographic and /or Substation)	Point of Connection Voltage	System Impact
		LTFTS: Within the Midway Area and southward LTFTS availability is marginal (i.e., less than 300-500 MW) due to the impact on 230 kV transmission facilities going South from Midway. Requests in greater amounts for LTFTS may require the upgrade or the construction of new 230 kV lines south of Midway to the area of Ranch. Such extensive construction would be of extended lengths requiring long lead times and clearance availability. Limited right-of-way will also extend project lead times. Northward LTFTS can be generally favorable and may be accommodated without major upgrades/new facilities. Note: The amount of total generation connected to Midway Substation is limited to approximately 3600MW taking into consideration a potential catastrophic event (e.g., the loss of the site and/or attendant transmission corridors), which event results in unacceptable system performance.
East Area	500/230 kV	GIS: Generally favorable for GIS in amounts less than 1200MW. Impact on short circuit levels on the 230 kV system may require the replacement of multiple breakers and various sections of OHGW in this area. LTFTS: Within the East Area and southward availability of LTFTS in amounts up to 600-800 MW area can be expected to be generally favorable. Depending on the connection of the generation, such amounts can be accommodated without major upgrades/new facilities. Larger requests for LTFTS may require the upgrade or the construction of new facilities. Due to limited right-of-way and clearance capabilities in this area construction of new facilities in this area will require long lead times. Northward LTFTS in amounts of 600-800MW may be generally favorable and may be accommodated without major upgrades/new facilities.
Southeast Area[1]	500/230 kV	GIS: Very favorable for GIS in amounts less than 800-1200 MW. Impact on short circuit levels on the 230 kV system may require the replacement of multiple breakers and various sections of OHGW in this area.

General Area (Geographic and /or Substation)	Point of Connection Voltage	System Impact
		LTFTS: Within the Southeast Area availability of LTFTS in amounts less than 800-1200 MW may be favorable and potentially accommodated without major upgrades/new facilities, since this area is a major load center. Larger requests for LTFTS may require the upgrade or the construction of new facilities, depending on if the generation is within the Southeast Area but not within the immediate vicinity of each other. Northward LTFTS also in amounts of 800-1200MW can be generally favorable and may be accommodated without major upgrades/new facilities. [1] *Over the next 4-6 years, due to the growing imbalance between generation and load in this area, substantial amounts of transmission upgrades may need to be constructed in Southeast Florida. The potential for a lengthy permitting process must be taken into account.*
North Area	500/230 kV	GIS: Generally favorable for GIS amounts less than 600-800 MW. Impact on short circuit levels on the 230 kV system may require the replacement of multiple breakers and various sections of OHGW in this area. LTFTS: Within the North Area LTFTS availability is marginal (i.e., 200-600 MW) due to the impact on 230, 138 and 115 kV transmission facilities. Sizable requests for LTFTS may require the upgrade or the construction of new transmission. Southward LTFTS availability is in the range of 200-600 MW depending on the connection of the generation due to the impact on 230 kV transmission facilities going south. Larger requests for LTFTS may require the upgrade or the construction of new 230 kV in the area of Ranch substation which are of extended lengths, requiring long lead times due to extensive construction and clearance availability. Northward requests for LTFTS can be generally favorable and may be potentially accommodated without major upgrades/new facilities.

General Area (Geographic and /or Substation)	Point of Connection Voltage	System Impact
Central-western Area	230 kV	GIS: Additional generation may require the replacement of multiple breakers and various sections of OHGW in this area. System stability is also of concern in this area. Critical clearing times are marginal and the addition of sizable amounts of new generation may require system reconfiguration and/or facility modifications. LTFTS: Within the Central-western Area and Southward LTFTS availability is marginal (i.e., less than 200-400 MW) without major upgrades/new facilities. Sizable amounts may require the upgrade of existing lines or the construction of a new 230 kV line from the West coast to the East coast of South Florida, and may adversely impact other systems (e.g., FPC, TEC, OUC)
South-western Area	230 kV	GIS: Additional generation may require the replacement of multiple breakers and various sections of OHGW in this area, and the splitting of the 230 kV Ft. Myers and/or Orange River Substations and attendant additional transmission lines. LTFTS: Within the South-western Area LTFTS generally available for amounts in the range of 200-400 MW. Larger requests for LTFTS may require the upgrade of existing lines or the construction of new 230 kV line from the West coast to the East coast of South Florida. Northward LTFTS is generally available but may adversely impact other systems (e.g., FPC, TEC, OUC, etc.) and may require the upgrade of existing lines or the construction of new 230 kV line from the West coast to the East coast of South Florida.

Other observations regarding transmission system and capabilities:

- The Southwest to Southeast Florida transfer capability is marginal. Additional transfers on this corridor may require the capability to be increased by upgrading existing facilities and/or adding new facilities. New facilities may require right-of-way which could lengthen project lead times. Note that the distances involving construction of new/upgrade facilities are in the 70-90 mile range and thus any expansion is likely to be costly and time consuming.

- The transfer capability across the 230 kV facilities South of Midway and into Ranch are marginal. Additional transfers on these facilities may require their respective capability to be increased by upgrading existing facilities and/or adding new facilities. New facilities may require right-of-way which could lengthen project lead times. Note that the distances involving construction of new/upgrade facilities are in the 20-30 mile range and thus any expansion is likely to be costly and time consuming. Additionally, clearances on the existing facilities to upgrade them or in the same right-of-way may require long lead times and may be difficult to attain.

- FPL currently has no availability for additional LTFTS from SERC into Florida.

- While it is generally advantageous to connect generation near load centers and/or the intended Point of Delivery, large amounts of new generation connected to the FPL 138 kV or 115 kV systems can result in the overload of the facilities at these voltage levels.

- Generally, except as noted above with respect to Midway substation, the amount of total generation connected to a substation is limited to approximately 4600MW taking into consideration a potential catastrophic event (e.g., the loss of the site and/or attendant transmission corridors), which event results in unacceptable system performance.

EXHIBIT 10

General Information Regarding FPL's Transmission System Capability, May 2003

Revision: May, 2003

General Information Regarding FPL's Transmission System Capability

Generator Interconnection Service ("GIS") And Long-Term Firm Transmission Service ("LTFTS")

Overview

- The intent of the document is to provide general information as to the capability of the FPL transmission system with respect to the provision of Generator Interconnection Service ("GIS") or Long-Term Firm Transmission Service ("LTFTS"). The information provided in this document takes into consideration all long-term firm obligations and commitments. The impacts associated with a specific request for GIS or LTFTS may differ substantially from the general information provided in this document. As such, while this information may serve as a preliminary aid to a generator developer or an entity requesting transmission service, the final determination of the impact of such request for GIS or LTFTS is based on the studies associated with such request, where such request lies within the respective Queue and the specifics associated with such requests.

Assumptions

- Previously performed GIS and LTFTS studies along with FPL's general knowledge and experience of the FPL transmission system.
- The information provided in this document takes into consideration all long-term firm obligations.

Information limitations:

- This document is only intended to provide general information and serve for preliminary due diligence work by the generator developer prior to requesting generation interconnection service and/or transmission service for a new generator. It is not intended to provide specific and accurate results for any particular new generation project.
- This document does not take into consideration other important factors to a generator such as water, fuel and the environment.
- This document is not specific to the areas/sites discussed. Distinct generation points of connection in close proximity may provide results different than the information provided in this document.

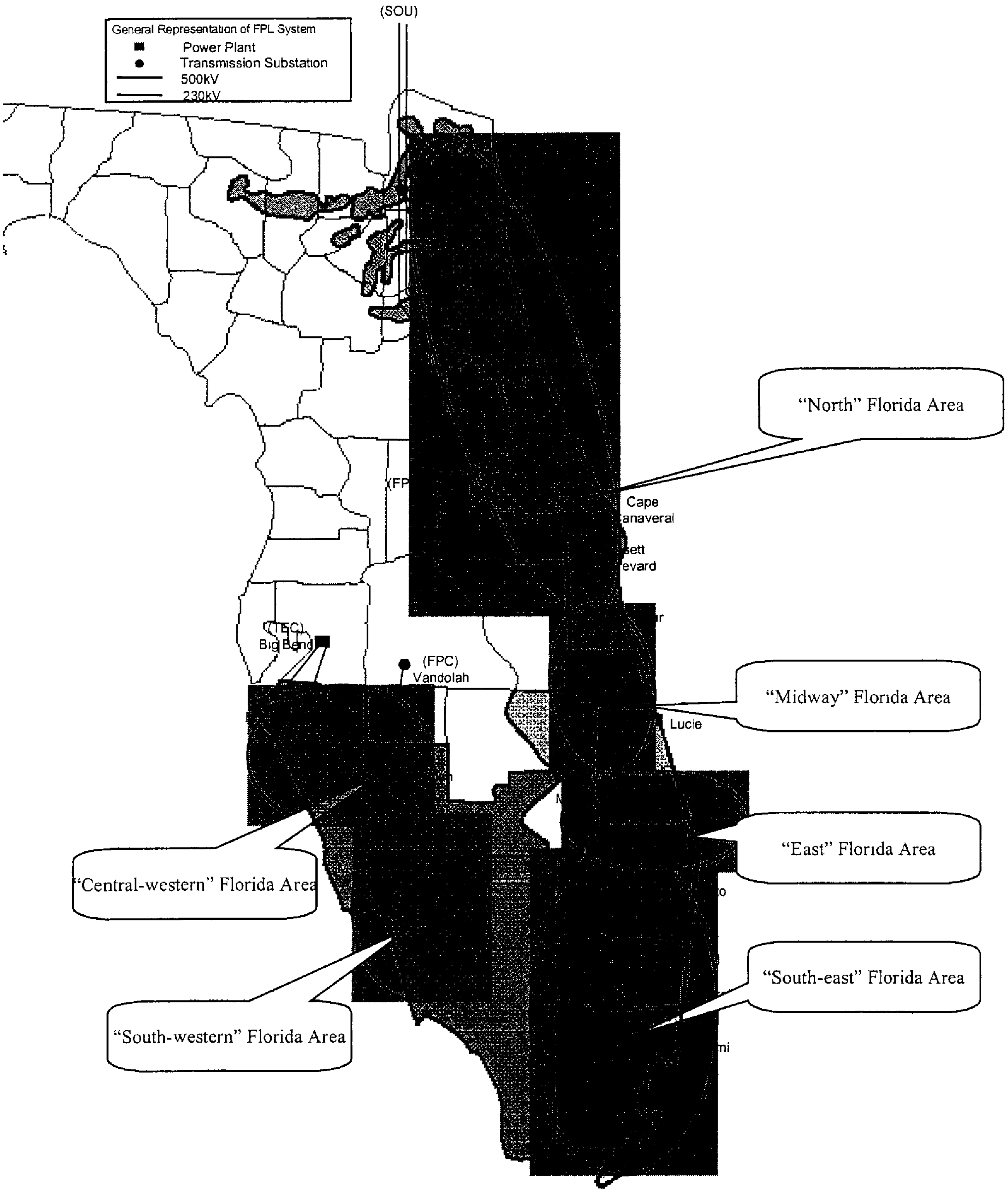
FPL does not make any representation regarding the information provided in this document. Entities interested in requesting an interconnection of generator or transmission service should regard this information as preliminary, generic, non-specific and subject to change, and as such should perform their own evaluations as part of their initial due diligence. Moreover, by providing this information FPL is not offering to purchase the output of any generation requesting GIS or LTFTS, nor does FPL warrant or otherwise guarantee the availability of Firm Transmission Service.

In order to determine the impact of a specific request for GIS or LTFTS an entity must request such service in accordance with FPL's Open Access Transmission Tariff and FERC Policy. The impact of a request for GIS or LTFTS may be dependent on a preceding request for GIS or LTFTS. Additionally, the information provided may become invalid as a result of requests for GIS or LTFTS being confirmed. Specifically, interconnection and transmission service requests change frequently and such changes can affect the results of any study at a particular location. Accordingly, reference should be made to FPL's OASIS for information to existing requests at or near a particular location. As such the information provided in this document is subject to change as a result of preceding requests for GIS or LTFTS that come to fruition and/or planned and unplanned changes in system conditions.

FPL may unilaterally update the information in this document at FPL's discretion.

Revision: May, 2003

Transmission Interconnection & Integration



General Area (Geographic and /or Substation)	Point of Connection Voltage	System Impact
Midway Area	500 kV	GIS: Generally favorable for GIS. Impact on short circuit levels on the 230 kV system may require the replacement of multiple breakers and various sections of Overhead Ground Wire ("OHGW") in this area. LTFTS: Within the Midway Area LTFTS availability is dependent on the impact on 230 kV transmission facilities South from Midway. Requests greater than 1200MW of LTFTS may require the upgrade or the construction of new 230 kV lines south of Midway to the area of Ranch substation which are of extended lengths requiring long lead times due to extensive construction and clearance availability. Limited right-of-way will also extend project lead times. Northward LTFTS in the amounts of 500-900 MW are generally favorable and potentially accommodated without major upgrades/new facilities. Note: The amount of total generation connected to Midway Substation is limited to approximately 3600MW taking into consideration a potential catastrophic event (e.g., the loss of the site and/or attendant transmission corridors), which event results in unacceptable system performance.
Midway Area	230 kV	GIS: Marginal capability is available due to impact on short circuit levels. The 230 kV system will first require the replacement of multiple breakers in this area and various sections of OHGW. Amounts in excess of 800+ MW may require the splitting of the Midway Substation. The installation could require a long lead time due to clearance availability. System stability is also of concern in this area. Critical clearing times are marginal and the addition of sizable amounts of new generation may require system reconfiguration and/or facility modifications. Also, work at or in the vicinity of Midway substation requiring clearances may need to be coordinated with an outage of St. Lucie nuclear power plant which is connected to Midway substation. LTFTS: Within the Midway Area and southward LTFTS availability is marginal (i.e., less than 300-500 MW) due to the impact on 230 kV transmission facilities going South from Midway. Requests in greater amounts for LTFTS may require the

General Area (Geographic and /or Substation)	Point of Connection Voltage	System Impact
		upgrade or the construction of new 230 kV lines south of Midway to the area of Ranch. Such extensive construction would be of extended lengths requiring long lead times and clearance availability. Limited right-of-way will also extend project lead times. Northward LTFTS can be generally favorable and may be accommodated without major upgrades/new facilities. Note: The amount of total generation connected to Midway Substation is limited to approximately 3600MW taking into consideration a potential catastrophic event (e.g., the loss of the site and/or attendant transmission corridors), which event results in unacceptable system performance.
East Area	500/230 kV	GIS: Generally favorable for GIS in amounts less than 1200MW connected to the 500 kV potentially requiring the replacement of multiple breakers and various sections of OHGW in this area. Impact on short circuit levels on the 230 kV system may require the replacement of multiple breakers and/or other fault current mitigation measures, and various sections of OHGW in this area. LTFTS: Within the East Area and southward availability of LTFTS in amounts up to 600-1100 MW area can be expected to be generally favorable. Depending on the connection of the generation, such amounts can be accommodated without major upgrades/new facilities. Larger requests for LTFTS may require the upgrade or the construction of new facilities. Due to limited right-of-way and clearance capabilities in this area construction of new facilities in this area will require long lead times. Northward LTFTS in amounts of 600-800MW may be generally favorable and may be accommodated without major upgrades/new facilities.
Southeast Area *(See Note 1 for important information)*	500/230 kV	GIS: Very favorable for GIS in amounts less than 800-1200 MW. Impact on short circuit levels on the 230 kV system may require the replacement of multiple breakers and various sections of OHGW in this area. LTFTS: Within the Southeast Area availability of LTFTS in amounts

General Area (Geographic and /or Substation)	Point of Connection Voltage	System Impact
		less than 800-1200 MW is favorable and potentially accommodated without major upgrades/new facilities, since this area is a major load center. Larger requests for LTFTS may require the upgrade or the construction of new facilities, depending on if the generation is within the Southeast Area or whether the generation is in the immediate vicinity of other generation. LTFTS from this area to the north also in amounts of 800-1200MW can be generally favorable and may be accommodated without major upgrades/new facilities. Similarly, larger requests for LTFTS may require the upgrade or the construction of new facilities, depending on whether the generation is within the Southeast Area or whether the generation is within the immediate vicinity of other generation. *Note 1:* *The Southeast area is the major load center in the State of Florida with load approximating 12,000 MW at peak and 6500 MW of generation in this area. The remaining power requirements in the Southeast area are met by transmission facilities providing import capability for power imports originating to the north and west of this area. The import capability into the Southeast area is finite (in the range of 6000-7000 MW comprised of about 5000-6000 MW from the north and the remaining 1000 MW from the west), and generally lower when generation and/or transmission facilities in and around the Southeast area are unavailable (e.g., due to maintenance or forced outage). Also, no other sources of power or imports are available to the Southeast area.* *In recognition of these unique characteristics of the Southeast area, a reliability reserve requirement needs to be maintained in the Southeast area. The reliability reserve requirement consists of a combination of remaining available import capability into the Southeast area and available generation in the Southeast Area. Additionally, the reliability reserve requirement must be of sufficient quantity so as to provide for effective operational flexibility such that maintenance of generation and transmission facilities in and around the Southeast area can be reliably performed taking into account the possibility of forced generation outages.* *Over the next several years the load growth in the Southeast area will exacerbate the imbalance between generation and load to the point where the reliability reserve requirement*

General Area (Geographic and /or Substation)	Point of Connection Voltage	System Impact
		required for this area (see discussion above) if not addressed could become deficient. As a result, depending on the specifics, over the next 4-6 years either, a combination of additional generation in and/or around the Southeast area, and/or substantial amounts of transmission upgrades will be needed. To the extent that transmission upgrades must be constructed, the potential for a lengthy permitting and construction process must be taken into account. Therefore, if a commitment to install additional generation at locations (e.g., in and/or around the Southeast area) and in amounts that would mitigate or materially postpone the need for transmission upgrades is not made within the next several years, the decision to move forward with transmission facilities will need to be made.
North Area	500/230 kV	GIS: Generally favorable for GIS amounts less than 600-800 MW. Impact on short circuit levels on the 230 kV system may require the replacement of multiple breakers and various sections of OHGW in this area. LTFTS: Within the North Area LTFTS availability is marginal (i.e., 200-600 MW) due to the impact on 230, 138 and 115 kV transmission facilities. Sizable requests for LTFTS may require the upgrade or the construction of new transmission. Southward LTFTS availability is in the range of 200-600 MW depending on the connection of the generation due to the impact on 230 kV transmission facilities going south. Larger requests for LTFTS may require the upgrade or the construction of new 230 kV in the area of Ranch substation which are of extended lengths, requiring long lead times due to extensive construction and clearance availability. Northward requests for LTFTS can be generally favorable and may be potentially accommodated without major upgrades/new facilities.

General Area (Geographic and /or Substation)	Point of Connection Voltage	System Impact
Central-western Area	230 kV	GIS: Additional generation may require the replacement of multiple breakers and/or other fault current mitigation measures, and various sections of OHGW in this area. System stability is also of concern in this area. Critical clearing times are marginal and the addition of sizable amounts of new generation may require system reconfiguration and/or facility modifications. LTFTS: Within the Central-western Area and Southward LTFTS availability is marginal (i.e., less than approximately 200MW) without major upgrades/new facilities. Sizable amounts may require the upgrade of existing lines or the construction of a new 230 kV line from the West coast to the East coast of South Florida, and may impact other systems (e.g., FPC, TEC, OUC)
South-western Area	230 kV	GIS: Additional generation may require the replacement of multiple breakers and various sections of OHGW in this area, and the splitting of the 230 kV Ft. Myers and/or Orange River Substations and attendant additional transmission lines. LTFTS: Within the South-western Area LTFTS generally available for amounts less than approximately 200 MW. Larger requests for LTFTS may require the upgrade of existing lines or the construction of new 230 kV line from the West coast to the East coast of South Florida. Northward LTFTS is generally available but may impact other systems (e.g., FPC, TEC, OUC, etc.) and may require the upgrade of existing lines or the construction of new 230 kV line from the West coast to the East coast of South Florida.

Other observations regarding transmission system and capabilities:

- Construction of new transmission facilities may require long lead times due to permitting and need proceeding requirements under the Transmission Line Siting Act, and acquisition of any necessary new rights-of-way.

- The Southwest to Southeast Florida transfer capability is marginal. Additional transfers on this corridor may require the capability to be increased by upgrading existing facilities and/or adding new facilities. New facilities may require right-of-way which could lengthen project lead times. Note that the distances involving construction of new/upgrade facilities are in the 70-90 mile range and thus any expansion is likely to be costly and time consuming.

- The transfer capability across the 230 kV facilities South of Midway and into Ranch are marginal. Additional transfers on these facilities may require their respective capability to be increased by upgrading existing facilities and/or adding new facilities. New facilities may require right-of-way which could lengthen project lead times. Note that the distances involving construction of new/upgrade facilities are in the 20-30 mile range and thus any expansion is likely to be costly and time consuming. Additionally, clearances on the existing facilities to upgrade them or in the same right-of-way may require long lead times and may be difficult to attain.

- FPL currently has no availability for additional LTFTS from SERC into Florida.

- While it is generally advantageous to connect generation near load centers and/or the intended Point of Delivery, large amounts of new generation connected to the FPL 138 kV or 115 kV systems can result in the overload of the facilities at these voltage levels.

- Generally, except as noted above with respect to Midway substation, the amount of total generation connected to a substation is limited to approximately 4900MW taking into consideration a potential catastrophic event (e.g., the loss of the site and/or attendant transmission corridors), which event results in unacceptable system performance.

EXHIBIT 11

RFP's Provisions on Submittal of Exceptions and Alternative Language for PPA

Long Island Power Authority

LIPA
Long Island Power Authority

May 30, 2003

To All Interested Proposers:

The Long Island Power Authority (the "Authority") is soliciting proposals from entities who are interested in one or more of the following: (1) developing a generating facility on Long Island and selling the capacity, associated energy, and ancillary services ("Products") to the Authority; (2) developing a new transmission line to Long Island that would accommodate the reliable delivery of Products from an off-Island generating facility; and (3) selling Products from a new or existing generating facility located off-Island to the Authority using a new or existing transmission line to Long Island. Each such proposal should supply the Authority with Products and/or new transmission capability of 250-600 MW for a term of ten, fifteen, or twenty years commencing no later than early summer 2007. The Authority will view favorably proposals with earlier in-service dates. The Authority may select one or more projects for development pursuant to this solicitation, or may decline to accept any or all proposals.

The Authority requests that no later than **3:00 p.m., August 11, 2003**, each Proposer submit six bound copies of a written response to the enclosed Request for Proposal ("RFP") to:

Mr. Jim Peterson
Director of Power Market Contracts
Long Island Power Authority
333 Earle Ovington Blvd., Suite 403
Uniondale, NY 11553

One unbound original, six copies, and a CD of your proposal shall also be sent to:

Long Island Power Authority
c/o Navigant Consulting, Inc.
Attn: Robert Kendall—Capacity and Energy RFP
1400 Old Country Road, Suite 402
Westbury, New York 11590-5156

A Proposers' Conference will be held at **10:00am** on **June 24, 2003**, at the Authority's office in Uniondale. Proposers interested in responding to this RFP should notify the Authority of their intent by filing a Notice of Intent to Submit Proposal (as provided in the RFP) no later than **5:00 p.m. , July 9, 2003.**

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For all projects, appropriate milestones will be set and deposits will be required to ensure that the in-service date will be met. Failure to meet the in-service date will result in appropriate liquidated damages. During the term of any PPA with the Authority, the new generation source and/or transmission facilities must meet all applicable New York ISO requirements.

III. Qualifications of Respondents

As part of its proposal evaluation, the Authority will consider the financial soundness of the Respondent, including any proposed guarantor. The Respondent must also have demonstrable experience and expertise in the areas of power plant and/or transmission development, financing, permitting, siting, construction and operation. Respondents who do not currently possess FERC market-based rate authority to make power sales at negotiated rates should indicate whether there are any impediments to obtaining such authorization prior to the commencement of the supply of Products at the time of submission of their proposal. Respondents must be members of the New York ISO or, in their proposal, commit that they will become members prior to the commencement of the supply of capacity and associated energy. Respondents are required to furnish all information requested in Section V of this RFP. Federal, state, and local governmental entities are not eligible to submit proposals in response to this RFP.

IV. Terms and Conditions of The Authority's Purchases

The agreement between the Authority and a Respondent resulting from this RFP will be a PPA setting forth the source of the Products, the price, the term, security, the point of interconnection, the fact that all capacity supplied must be in compliance with all applicable New York ISO and FERC requirements, and other contract terms and conditions typically contained within PPAs. The Authority will provide a PPA to potential Respondent(s) ("LIPA PPA") at the Proposers' Conference. In their proposals, Respondents must provide pricing information based on their acceptance of, or exceptions to, the terms and conditions contained in the LIPA PPA. Such Respondents must propose specific suggested language for each exception taken. The nature and extent of exceptions, if any, taken to the LIPA PPA will be an important factor considered by the Authority during its evaluation of proposals.

V. Contents of Proposals

To be considered, proposals must contain, at a minimum, the following information:

a. Name, address and telephone number of Respondent (and name, address, telephone number, and e-mail address of the contact person for Respondent in connection with its proposal), legal status of Respondent (corporation, partnership, limited liability company, etc.), date formed, jurisdiction of organization, and identification of any relevant affiliates. If Respondent proposes to have a guarantor guaranty its obligations, the same information as above shall be provided with respect to the

Respondents must indicate in their proposal what information, if any, is proprietary and confidential. Proposers are hereby advised that the Authority is subject to the New York State Freedom of Information Law ("FOIL"). Material marked "Confidential and Proprietary" will be treated as such to the extent consistent with the Authority's legal obligations under the FOIL, other applicable law, regulation or legal process, and will not be disclosed by the Authority to third parties, other than the Authority's consultants who will assist in the evaluation of the proposals.

VI. Evaluation Criteria

Each proposal will be subject to evaluation by the Authority based upon an overall assessment of its merits using criteria, which include (not necessarily listed in the order of importance):

- All-in costs to LIPA's ratepayers, including costs for required transmission reinforcements;
- Risk of cost increases to LIPA's ratepayers resulting from factors such as firmness of fuel transportation, technical attributes of project, and contractual obligations imposed on the Authority;
- Respondent's experience in developing and operating similar projects;
- Respondent's creditworthiness;
- Improvement to local reliability;
- Product deliverability;
- Furtherance of supplier diversity;
- Enhancement to wholesale competition;
- Impact on the environment;
- Exceptions taken to terms and conditions in LIPA PPA; and
- Ability to meet the Authority's expressed operating dates.

The Authority will give proposals containing the following attributes (not necessarily listed in the order of importance) more favorable consideration:

- Proposals with summer 2006 in service dates for all or a portion of the project;
- Projects that interconnect at LIPA's Newbridge Road, Ruland Road or Pilgrim substations;
- Proposals from Respondents that do not currently own any substantial generation on Long Island since it is the Authority's objective to encourage the development of a fully competitive wholesale generation market on Long Island;
- The extent to which for proposals of 15 or 20 years the Respondent retains a merchant portion whereby a portion of the total output of the proposed generating facility will be retained for sale in the competitive market;
- Proposals from Respondents that have generating facilities with dual fuel capability and/or firm, 365-days/year gas transportation so that the project does not experience any expected curtailments during any contract year. (However, the Authority will entertain proposals of 335-days/year gas transportation or better to the extent that firm gas transportation is not available); and
- Proposals in which the Respondent demonstrates a willingness to accept the terms and conditions set forth in the LIPA PPA.

Portland General Electric Co.

Portland General Electric Co.

REQUEST FOR PROPOSALS

Power Supply Resources

June 18, 2003

PGE

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Contract Terms and Conditions

Energy and Capacity Purchase Agreements

The contract templates for power and capacity purchases are included in appendices as follows:

- Appendix L –Firm Physical Wholesale Energy Purchase and Sale Agreement.
- Appendix M – Physical Capacity Purchase and Sale Agreement.
- Appendix N – Capacity Exchange Agreement.
- Appendix O– Tolling Agreement.
- Appendix P – Firm Financial Energy and Capacity Purchase and Sale Agreement.

Bidders must use one or more of the purchase agreement templates included in this RFP, and must include any proposed revisions to the contract (shown in red-line) as part of their response package to this RFP. PGE will evaluate all proposed revisions, but is under no obligation to accept any revisions or adopt any changes. Changes to terms and conditions or revisions to the templates will be discussed with Bidders selected for post-bid negotiations.

Ownership Position in an Energy Resource

Bidders submitting a bid for an ownership position in an energy resource are requested to provide as part of their response package to this RFP the documents identified in Appendix E. PGE will consider the terms and conditions in those documents, but will be under no obligation to accept them without modification. Changes to terms and conditions or revisions to the documents will be discussed with Bidders selected for post-bid negotiations.

EXHIBIT 12

Supporting Affidavits

STATE OF FLORIDA
COUNTY OF MIAMI DADE

AFFIDAVIT OF STEVEN R. SIM

Steven R. Sim, being first duly sworn, deposes and says:

1. My name is Steven R. Sim. My business address is 9250 West Flagler Street, Miami, Florida 33174. I am employed by Florida Power & Light Company ("FPL") as a Supervisor in the Resource Assessment and Planning Department. In my capacity as Supervisor for the Resource Assessment and Planning Department, I am responsible for determining FPL's future capacity needs and evaluating resource options to determine the best choice for meeting those needs. I have previously testified before the Florida Public Service Commission on a number of occasions in regard to matters pertaining to FPL's resource planning.

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

3. In 1979 I joined FPL. From 1979 until 1991 I worked in various departments including Marketing, Energy Management Research and Load Management where my responsibilities concerned the development, monitoring, and cost-effectiveness of demand side management (DSM) programs. In 1991 I joined my current department, then named the System Planning department, as a Supervisor whose responsibilities included the cost-effectiveness analyses of a variety of individual supply and DSM options. In 1993 I assumed my present position.

4. I have reviewed the Florida Partnership for Affordable Competitive Energy's ("PACE") Objections filed on September 4, 2003 to FPL's 2003 Request for Proposals for

Resource Need for 2007 ("RFP") challenging FPL's Evaluation Fee (PACE Objection M) and the response to such objection reflected in FPL's Response filed September 9, 2003.

5. I am aware of and hereby verify and affirm that the facts set forth in FPL's response to PACE Objection M as set forth in Section I(G) of FPL's Response are true and correct to the best of my knowledge and belief. This response was developed with my input and supports the rejection of PACE Objection M as addressed in FPL's Response.

FURTHER AFFIANT SAYETH NOT.

Steven R. Sim

STEVEN R. SIM

STATE OF FLORIDA
COUNTY OF MIAMI DADE

The foregoing instrument was signed, sworn to and subscribed before me this 9 day of September, 2003 by STEVEN R. SIM, who is personally known to me ✓ or produced _______ ____________________ as identification and who did take an oath.

Bertila Estopinales
NOTARY PUBLIC - STATE OF FLORIDA
BERTILA ESTOPINALES
Type/Print Name

My commission expires:

BERTILA ESTOPINALES
MY COMMISSION # DD 151015
EXPIRES: January 14, 2007
Bonded Thru Notary Public Underwriters

STATE OF FLORIDA
COUNTY OF PALM BEACH

AFFIDAVIT OF GERARD YUPP

Gerard Yupp, being first duly sworn, deposes and says:

1. My name is Gerard Yupp. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL") as the Manager of Regulated Wholesale Power Trading in the Energy Marketing and Trading Division. I have personal knowledge of the matters stated in this Affidavit.

2. I received a Bachelor of Science Degree in Electrical Engineering from Drexel University in 1989 and a Master of Business Administration Degree from Florida Atlantic University in 1994.

3. I joined the Protection and Control Department of FPL in 1989 as a Field Engineer and worked in the area of relay engineering. In November of 1996 I took the position of a real-time power trader in the Energy Marketing and Trading Division. I moved from real-time trading to short term power trading and assumed my current position in February 1999.

4. I am responsible for supervising the daily operations of wholesale power trading as well as developing longer term power and fuel strategies. Daily operations include: fuel allocation and fuel burn management for FPL's oil and/or natural gas burning plants, coordination of plant outages with wholesale power needs, real-time power trading, short term power trading, transmission procurement and scheduling. Longer term initiatives include conducting monthly fuel planning and evaluating opportunities within the wholesale power markets based on forward market conditions, FPL's outage schedule, fuel prices and transmission availability.

5. I have reviewed the Florida Partnership for Affordable Competitive Energy's ("PACE") Objections filed on September 4, 2003 to FPL's 2003 Request for Proposals for Resource Need for 2007 ("RFP") challenging FPL's dual fuel requirements as unfair and onerous (PACE Objection J) and the response to such objection reflected in FPL's Response filed September 9, 2003.

6. I am aware of and hereby verify and affirm that the facts set forth in the response to PACE Objection J, as set forth in Section I (F) of FPL's Response to PACE's Objections, are true and correct to the best of my knowledge and belief. This response was developed with my input and supports the rejection of PACE's objection relating to dual fuel requirements as addressed in FPL's Response.

7. Affiant says nothing further.

Gerard Yupp

GERARD YUPP

STATE OF FLORIDA
COUNTY OF PALM BEACH

The foregoing instrument was signed, sworn to and subscribed before me this 8th day of September, 2003 by GERARD YUPP, who is personally known to me ✓ or produced as identification and who did take an oath.

MARIE B. LOPEZ
MY COMMISSION # CC 955272
EXPIRES: July 17, 2004
Bonded Thru Notary Public Underwriters

NOTARY PUBLIC - STATE OF FLORIDA
Marie B. Lopez
Marie B. Lopez
Type/Print Name

My commission expires: 7/17/04

STATE OF FLORIDA
COUNTY OF MIAMI DADE

AFFIDAVIT OF WILLIAM ROBERT SCHONECK, JR.

William Robert Schoneck, Jr., being first duly sworn, deposes and says:

1. My name is William Robert Schoneck, Jr. My business address is 4200 West Flagler Street, Miami, Florida 33134. I am employed by Florida Power & Light Company ("FPL") as the Manager of Transmission Planning and have held this position since October of 1993. I have personal knowledge of the matters stated in this Affidavit.

2. I received a Bachelor of Science Degree in Electrical Engineering from the University of Florida in 1973 and a Master in Business Administration from Florida International University in 1982.

3. I have been employed by FPL since 1973. In that time I have held various positions. Immediately prior to my present position, I was the Manager of Transmission Planning in the Power Systems Business Unit at FPL. My responsibilities under my current position as Manager of Transmission Planning in the Transmission Services and Planning Group include managing the group that is responsible for the planning, coordination and development of FPL's transmission expansion in order to meet FPL customers' needs.

4. I currently participate on various committees of the Florida Reliability Coordinating Council ("FRCC"). The FRCC is a voluntary organization comprise of investor-owned utilities, municipal electric utilities, rural electric cooperatives and others in Florida. One of the purposes of the FRCC is to coordinate planning and operation of generation and transmission by its members. FRCC standards are consistent with and complementary to those of the North American Electric Reliability Council.

5. I have reviewed the Florida Partnership for Affordable Competitive Energy's ("PACE") Objections filed on September 4, 2003 to FPL's 2003 Request for Proposals for Resource Need for 2007 ("RFP") challenging FPL's Southeast Florida location preference (PACE Objection A), alleged reservation of transmission capacity (PACE Objection H), and FPL's recognition of the costs of transmission losses and increased operating costs of Southeast Florida Generation in the RFP (PACE Objection G), and the responses to such objections reflected in FPL's Response filed September 9, 2003.

6. I am aware of and hereby verify and affirm that the facts relating to transmission impact issues in FPL's responses to PACE Objections A and H, and the facts set forth in FPL's responses to PACE Objection G as set forth in Section(s) III(A), (B) and (C) of FPL's Response to PACE's Objections are true and correct to the best of my knowledge and belief. These responses were developed with my input and support the rejection of those portions of PACE's Objections as addressed in FPL's Response.

FURTHER AFFIANT SAYETH NOT.

William Robert Schoneck Jr.

WILLIAM ROBERT SCHONECK, JR.

STATE OF FLORIDA
COUNTY OF MIAMI DADE

The foregoing instrument was signed, sworn to and subscribed before me this 5th day of September, 2003 by WILLIAM ROBERT SCHONECK, JR., who is personally known to me __ or produced _______________ as identification and who did take an oath.

NOTARY PUBLIC - STATE OF FLORIDA
LOURDES V. WONGDEN
Type/Print Name

My commission expires:

FPL\schoneck.affidavit

OFFICIAL NOTARY SEAL
LOURDES V WONGDEN
NOTARY PUBLIC STATE OF FLORIDA
COMMISSION NO. CC883985
MY COMMISSION EXP. OCT. 28,2003

STATE OF FLORIDA
COUNTY OF MIAMI DADE

AFFIDAVIT OF RENE SILVA

Rene Silva, being first duly sworn, deposes and says:

1. My name is Rene Silva. My business address is 9250 West Flagler Street, Miami, Florida 33174. I am employed by Florida Power & Light Company ("FPL") as Director of Resource Assessment and Planning. As Director of Resource Assessment and Planning for FPL, I manage the group that is responsible for the development of FPL's integrated resource plan and other related activities, such as analysis of demand side management programs, system production cost projections, development of FPL's demand and energy forecasts, and the administration of wholesale power purchase agreements. I have personal knowledge of the matters stated in this Affidavit.

2. I graduated from the University of Michigan with a Bachelor of Science Degree in Engineering Science in 1974. I then earned a Masters Degree in Mechanical Engineering from San Jose State University in 1978. Subsequently, in 1986, I earned a Masters Degree in Business Administration from the University of Miami.

3. Prior to working for FPL, I was employed by the Nuclear Energy Division of the General Electric Company in the area of nuclear fuel design. I joined FPL in 1978, and since that time, I have held a number of positions including Director, Fuel Resources Department and Manager of Fuel Services. In 1998 I was named Manager of Business Services in the Power Generation Division. I was appointed to my current position on May 1, 2002.

4. I have reviewed the Florida Partnership for Affordable Competitive Energy's ("PACE") Objections filed on September 4, 2003 to FPL's 2003 Request for Proposals for

Resource Need for 2007 ("RFP") challenging FPL's Minimum Requirement concerning Financial Viability or Minimum Debt Rating (PACE Objection C), FPL's requirement that Proposers with proposals based on new generation be responsible for the location, development and permitting of proposed sites and prohibiting co-location at FPL's Turkey Point Site (PACE Remedy in Objection A), FPL's Minimum Requirement of Acceptance by a Proposer or Seller of its Regulatory Modifications Provision (PACE Objection B), FPL's Southeast Florida location preference (PACE Objection A), alleged reservation of transmission capacity (PACE Objection H), and FPL's draft Purchased Power Agreement and Exceptions Requirements (PACE Objection F), and the responses to such objections reflected in FPL's Response filed September 9, 2003.

5. I am aware of and hereby verify and affirm that the facts set forth in FPL's responses to the foregoing Objections of PACE, as set forth in Sections I(A) as such is limited to the statement concerning the combined total MW output of certain Independent Power Producers, I(D), I(H) except for observations regarding project financeability, III(A) and III(B) except for statements relating to transmission impact issues, and IV(A) of FPL's Response are true and correct to the best of my knowledge and belief. These responses were developed with my input and support the rejection of those portions of PACE's Objections as addressed in FPL's Response.

FURTHER AFFIANT SAYETH NOT.

RENE SILVA

STATE OF FLORIDA
COUNTY OF MIAMI DADE

The foregoing instrument was signed, sworn to and subscribed before me this 9 day of September, 2003 by RENE SILVA, who is personally known to me X or produced ______________ as identification and who did take an oath.

NOTARY PUBLIC - STATE OF FLORIDA

MAURA HERNANDEZ
Type/Print Name

My commission expires: 5/25/04

Maura Hernandez
MY COMMISSION # CC913575 EXPIRES
May 25, 2004
BONDED THRU TROY FAIN INSURANCE, INC.

FPL\silva.affidavit

STATE OF FLORIDA
COUNTY OF PALM BEACH

AFFIDAVIT OF GARY V DRIEBE

Gary V Driebe, being first duly sworn, deposes and says:

1. My name is Gary V Driebe. My business address is 700 Universe Blvd., Juno Beach, Florida 33410. I am employed by Florida Power & Light Company ("FPL") as the General Manager of the Turbine Fleet Team in the Power Generation Business Unit and have held this position since 1999. I have personal knowledge of the matters stated in this Affidavit.

2. I received a Bachelor of Science Degree in Electrical Engineering from the University of South Florida in 1974.

3. I have been employed by FPL since 1985. In that time I have held various positions. Prior to my present position, I was Production Manager of the Martin Combined Cycle Plant. My current responsibilities as General Manager of the Turbine Fleet Team in the Power Generation Business Unit include managing a group of technical specialist that provide Technical Services in the areas of Gas and Steam Turbines. During my 29 year career in Power Generation I have held various positions in the areas of power plant construction, start-up and operation.

4. I have reviewed the Florida Partnership for Affordable Competitive Energy's ("PACE") Objections filed on September 4, 2003 to FPL's 2003 Request for Proposals for Resource Need for 2007 ("RFP") challenging FPL's Minimum Experience of Proposers (PACE Objection N), and the response to such objection reflected in FPL's Response filed September 9, 2003.

5. I am aware of and hereby verify and affirm that the facts relating FPL's response to PACE Objection N challenging FPL's Minimum Experience of Proposers, as set forth in Section I (C) of FPL's Response to PACE's Objections, are true and correct to the best of my knowledge and belief. This response was developed with my input and supports the rejection of this portion of PACE's Objections as addressed in FPL's Response.

6. Affiant says nothing further.

Gary V Driebe

GARY V DRIEBE

STATE OF FLORIDA
COUNTY OF PALM BEACH

The foregoing instrument was signed, sworn to and subscribed before me this 8 day of September, 2003 by GARY V. DRIEBE, who is personally known to me _____ or produced as identification and who did take an oath.

NOTARY PUBLIC - STATE OF FLORIDA

PETER E. McGOVERN

Type/Print Name

My commission expires:

PETER E. McGOVERN
MY COMMISSION # DD 081738
EXPIRES: March 12, 2006
1-800-3-NOTARY FL Notary Service & Bonding, Inc.

STATE OF FLORIDA
COUNTY OF PALM BEACH

AFFIDAVIT OF MORAY P. DEWHURST

Moray P. Dewhurst, being first duly sworn, deposes and says:

1. My name is Moray P. Dewhurst. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL") as Senior Vice President of Finance and Chief Financial Officer of FPL. I have personal knowledge of the matters stated in this Affidavit.

2. I received a Bachelor's Degree in Naval Architecture from MIT and a Master's Degree in Management, with a concentration in Finance, from MIT's Sloan School of Management. I have approximately twenty years of experience consulting to Fortune 500 and equivalent companies in many different industries on matters of corporate and business strategy. Much of my work has involved financial strategy and financial re-structuring. I was appointed to my present position in July of 2001.

3. I have reviewed the Florida Partnership for Affordable Competitive Energy's ("PACE") Objections filed on September 4, 2003 to FPL's 2003 Request for Proposals for Resource Need for 2007 ("RFP") challenging FPL's Minimum Requirement concerning Financial Viability or Minimum Debt Rating (PACE Objection C), FPL's Completion and Performance Security Requirements (PACE Objection D) and FPL's application of an Equity Adjustment (PACE Objection I), and the responses to such objections reflected in FPL's Response filed September 9, 2003.

4. I am aware of and hereby verify and affirm that the facts set forth in FPL's responses to PACE Objections B, C, D, and I as set forth in Sections II(H), I(A), I(B) and III(D), respectively, of FPL's Response to PACE's Objections are true and correct to the best of my knowledge and

belief.

FURTHER AFFIANT SAYETH NOT.

Moray P. Dewhurst

MORAY P. DEWHURST

STATE OF FLORIDA
COUNTY OF PALM BEACH

The foregoing instrument was signed, sworn to and subscribed before me this 9 day of September, 2003 by MORAY P. DEWHURST, who is personally known to me ✓ or produced ______________ as identification and who did take an oath.

Elsa M Akin

NOTARY PUBLIC - STATE OF FLORIDA

ELSA M AKIN

Type/Print Name

My commission expires:

ELSA M. AKIN
MY COMMISSION # DD 222228
EXPIRES: October 12, 2007
Bonded Thru Notary Public Underwriters

FPL\dewhurst.affidavit

CERTIFICATE OF SERVICE

I hereby certify that on this the 9th day of September, 2003 a copy of the forgoing Response Of Florida Power & Light Company, including supports exhibits and affidavits, was served by either personal service (*) or First Class United States Mail upon the following persons:

Jon Moyle, Jr.
c/o Moyle Law Firm
118 North Gadsden Street
Tallahassee, FL 32301

By: ______________________
Charles A. Guyton