LAW OFFICES
OF
LESLIE J. PAUGH, P.A.

LESLIE J. PAUGH
ELECTRONIC MAIL ADDRESS:
lpaugh@paugh-law.com

2473 CARE DRIVE, SUITE 3
TALLAHASSEE, FL 32308

TELEPHONE (850) 656-3411
FACSIMILE (850) 656-7040

MAILING ADDRESS:
POST OFFICE BOX 16069
TALLAHASSEE, FLORIDA 32317-6069

June 21, 2002

VIA HAND DELIVERY

Ms. Blanca S. Bayó, Director
Division of Commission Clerk and
Administrative Services
FLORIDA PUBLIC SERVICE COMMISSION
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 020233-EI; Joint Post-Workshop Comments and Request for Hearing of Calpine Corporation, Mirant Americas Development, Inc., Duke Energy North America , LLC to Order No. PSC-02-0459-PCO-EI.

Dear Ms. Bayó:

Enclosed for filing please find one (1) original and fifteen (15) copies of the Joint Post-Workshop Comments and Request for Hearing, submitted for filing in the above referenced docket. Please also find the enclosed diskette, containing an electronic version of the Filing in Word format.

Please acknowledge receipt of this document by time/date stamping the enclosed additional copy of the Filing, as indicated.

Very truly yours,

Leslie J. Paugh

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of GridFlorida Regional Transmission Organization (RTO) Proposal	)))	Docket No. 020233-EI Filed: June 21, 2002

JOINT POST-WORKSHOP COMMENTS AND REQUEST FOR HEARING

Come now, Calpine Corporation, Mirant Americas Development, Inc., and Duke Energy North America, LLC ("Joint Commenters") and hereby file their Joint Post-Workshop Comments and Request for Hearing pursuant to Order Establishing Procedure, Order No. PSC-02-0459-PCO-EI, issued April 3, 2002.

I. Introduction

Joint Commenters appreciate the opportunity to have presented Joint Pre-Workshop Comments on the GridFlorida Regional Transmission Organization ("RTO") compliance filing of Applicants Florida Power & Light Company ("FPL"), Florida Power Corporation ("FPC") and Tampa Electric Company ("TECO") (collectively "Applicants") as well as the opportunity to present several of their positions during the Commission Workshop held on May 29, 2002 ("May 29 Workshop). However, notwithstanding the informal process that has transpired to date, most, if not all, of Joint Commenters outstanding concerns with the GridFlorida compliance filing have not been addressed thus highlighting the need for a formal evidentiary hearing in Phase II of this proceeding.

In the interest of brevity and focus, Joint Commenters will diverge from the format of their previous filing. First, rather than revisit the myriad of substantive issues raised in their Joint Pre-Workshop Comments filed on May 8, 2002, Joint Commenters, by this reference, incorporate herein and reassert all of the positions taken in that pleading. Additionally, Joint Commenters reserve the right to file a reply to Post-Workshop Comments filed by the Applicants filed concomitantly with these Joint Comments. Second, Joint Commenters will provide a detailed numerical demonstration of the economic and functional superiority of Financial Transmission Rights ("FTRs") with Locational Marginal Pricing ("LMP") over the Physical Transmission Rights ("PTRs") and balanced schedule requirement model. Third, Joint Commenters will address some of the representations made by various parties during the May 29 Workshop. Fourth, Joint Commenters will present a proposed preliminary list of disputed issues of material fact to be addressed during the hearing in this docket.

II. Economic and Functional Superiority of Financial Transmission Rights with Locational Marginal Pricing.

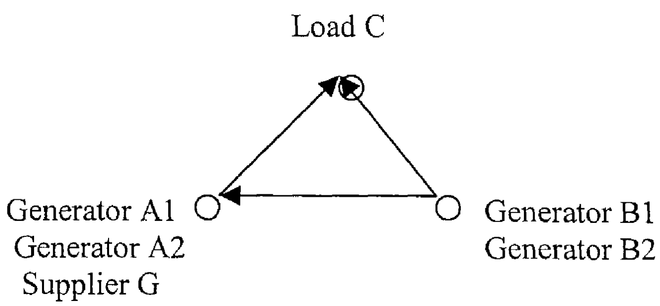
The following presents a series of numerical examples demonstrating how the FTR with LMP model works. In addition, Joint Commenters have included numerical examples comparing the FTR/LMP model against the PTR with balanced schedules model that demonstrate the manner in which market outcomes could easily be manipulated by incumbents under the PTR paradigm.

In general, the LMP/FTR model will result in the least cost generation being dispatched to the largest number of customers in the GridFlorida region. The LMP/FTR model is substantially more efficient and cost-effective than the proposed GridFlorida PTR model for addressing aggregate Florida needs. [Tr. 169] Under the LMP/FTR paradigm, participant directed generation schedules and physical transactions are considered in combination with other supply options through a least cost scheduling solution that assures the lowest aggregate cost to meet aggregate demand. Transparent locational marginal prices discipline physical transactions without socialization but with price certainty. Reliability is served and costs rationally minimized because price transparency via LMP posting enables market participants to make appropriate decisions for their transactions in the appropriate time frames.

By contrast, as is demonstrated below, under the Applicants' PTR/balanced schedule requirement approach, access to price information and least cost supply are both severely restricted and the potential for market power abuse is great. Access to competing, lower cost supplies is diminished as a result of the flowgate requirement and the balanced schedule requirement. Under a balanced schedule regime, Scheduling Coordinators ("SCs") that possess generation but not load responsibility will not be entitled to submit generator start-up and operation schedules to the RTO resulting in administrative withholding of lower cost supplies. Similarly, other than through advance bilateral arrangements (including sufficient PTR procurement), SCs with load responsibility are not allowed the opportunity to have merchant generation satisfy their demand at costs lower than their self-generation. In addition, neither the balanced schedule requirement nor the PTR based hour-by-hour scheduling evaluations factor in real world generator unit commitment considerations, such as startup, shut down, and minimum run times, resulting in barriers to scheduling of merchant generation and hence consumers access to those supply options. [Tr. 156] The LMP/FTR model does not require balanced schedules. Rather, it utilizes a day-ahead market to ensure that sufficient generation is on-line to provide least cost, reliable supply resources and allows the RTO to react to the real time changes in the most cost effective manner.

Like the balanced schedule requirements, the Applicants' physical rights based flowgate congestion management approach effectively restricts the market's ability to achieve least cost supply. For example, a transaction will not flow (e.g., a generator cannot be started) unless the requestor holds sufficient rights over *all* impacted flowgates. A PTR holder with knowledge of a requestor's need for a full compliment of rights can withhold transmission capacity which will force uneconomic dispatch (presumably to favor the holder's own units, or the future sale price of its PTRs), decreased reliability and the potential for windfall profits - all to the detriment of the Florida ratepayers. In short, under a PTR approach, transparency is never achieved, knowledge of the marketplace is never gained and the sum of participants' generation schedules never assures lowest cost. [Tr. 181] By contrast, under the LMP/FTR model, FTR holders cannot force withholding of any generation, and RTO directed dispatch will provide for the most efficient use of the grid at the least cost to meet aggregate demand.

NUMERICAL EXAMPLE DEMONSTRATING FINANCIAL TRANSMISSION RIGHTS WITH LMP CONGESTION MANAGEMENT



<u>GENERAL ASSUMPTIONS:</u>

At Point C:

A load withdraws its power at this point at a rate of 500 Megawatts ("MW") each on-peak hour and 200MW's each off-peak hour.

At Point A:

A1 is a 200MW generator interconnected to point A with an incremental cost of \$26/megawatt-hour ("mwh").

A2 is a 300MW generator interconnected to point A with an incremental cost of \$27/mwh.

G is an electric supply electrically interconnected to point A that reflects the incremental price of one or more generators in the balance of the network equal to \$30/mwh.

At Point B:
B1 is a 300MW generator interconnected to point B with an incremental cost of $22/mwh.
B2 is a 300MW generator interconnected to point B with an incremental cost of $23/mwh.

A1 and A2 are existing generators owned by Investor Owned Utilities ("IOU") to meet retail load service needs. B1 and B2 are new, more efficient generators built by Independent Power Producers ("IPPs"). While ratepayers must, through retail rates, pay down the 30-year mortgage of debt on A1 & A2 plus depreciation and return on the IOU's equity, the capital risk of B1 and B2 is entirely borne by the IPP developers. Of course, IPP developers can reduce their risk through forward bilateral sales to load serving entities that seek to lock in a known rate to avoid uncertainty. Under LMP/FTR based congestion management, consumers are provided automatic access to the output of all generation. Consumers' automatic access to output occurs without requiring the load serving entities ("LSEs") to buy generation beyond their existing portfolios in advance unless the LSE perceives benefit to some forward hedging. Merchant generation (B1 & B2) and all LSEs' generation not used to meet their own needs would be subject to both day-ahead and real time energy auctions to deliver the lowest aggregate cost to satisfy Florida demand. The auctions would occur through a computerized auction process that satisfies aggregate demand in Florida using an algorithm that performs the least cost auction outcome for each iteration which, in real time, occurs every ten minutes. This process is similar to an eBay type of auction except that, unlike eBay, many energy auction purchase decisions are interrelated and collectively, all of the auction decisions are subject to compliance with system security constraints. As such, full efficiency requires computerized automation of the auction evaluations and decisions – while execution of the purchase occurs through RTO dispatch instructions. In the process of calculating that optimum mix, the computer also calculates the incremental cost to serve one more Megawatt of load at each location. No bilateral trading or physical scheduling scheme can approximate the level of real time cost efficiency given the number and complexity of the interactions.

A. <u>LMP/FTR Examples</u>:

A. Assume no portion of B1 or B2 are sold forward through bilateral sales. The IOU load at C owns A1 and A2. The IOU can either schedule its generation to meet its expectation of load (attempt to balance) or submit its generation at its incremental price and let the automatic auction clearing process satisfy its (and other) demand needs at the lowest price. In the first example, consider the hypothetical case where an IOU can predict its demand exactly and self-schedules to meet that demand:

	Morning Off-peak	Peak Hours	Evening Off-peak
Generator A1 – 26	200	200	200
Generator A2 – 27	0	300	0
Generator B1 – 22	0	0	0
Generator B2 – 23	0	0	0
Supplier G – 30			
Total Generation	200	500	200
Total Generation Cost per hour	$5200	$13,300	$5200
Lost Opportunity Cost to Consumers at C per hour	200 x ($26-22) = $800	200 x ($26-22) = $1200 100 x (27-22) = $500 200 x (27-23) = $800 Total = $2500	200 x ($26-22) = $800
Load @ C	200	500	200

In this example, the load serving entity self-scheduled all of its own needs (similar to that which would be <u>required</u> under the GridFlorida proposed approach) and despite opportunities to deliver lower costs to consumers, the LSE chose to meet supply with less efficient generation. Under LMP, however, the locational price at C would reveal a $22/mwh locational cost to meet the next MW of load at C in all hours. This price would be visible to both the IOU LSE and the Florida Public Service Commission ("FPSC"). It is likely that either the IOU would recognize this opportunity to save money for its retail customers or the FPSC would identify and appropriately inquire why the IOU was self-supplying 100% of needs while cheaper supplies exist through the spot market.

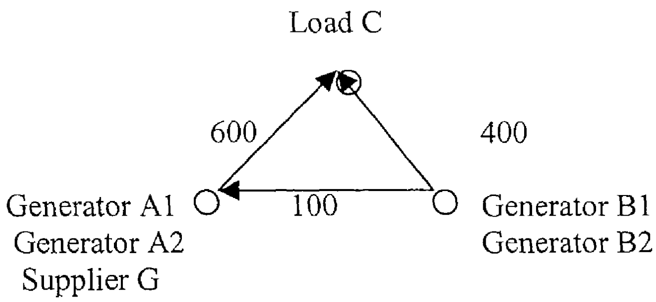
B. In the next example, the IOU continues to self supply 50% of its needs and bid in its generation at incremental prices to either self-supply (if its generation is dispatched as the least cost solution by the RTO) all or part of the remaining 50% of demand or buy from the spot market.

	Morning Off-peak	Peak Hours	Evening Off-peak
Generator A1 – 26	100	200	100
Generator A2 – 27	0	50	0
Generator B1 – 22	100	250	100
Generator B2 - 23	0	0	0
Supplier G - 30			
Total Generation	200	500	200
Total Generation Cost per hour	$4800	$12,050	$4800
Savings realized per hour	100 x ($26-22) = $400	250 x ($27-22) = $1250	100 x ($26-22) = $400
Remaining lost opportunity cost to Consumers at C per hour	100 x ($26-22) = $400	50 x (27-22) = $250 200 x (26-23) = $600 Total = $850	100 x ($26-22) = $400
Load @ C	200	500	200

In this example, the LSE self-scheduled only 50% of its own needs. It saved money for its consumers by buying 50% of their needs in the spot market. Through submission of its own generation at its incremental energy price for RTO dispatch, it hedged its consumers' exposure to spot market prices. Even if both B1 and B2 were simultaneously unavailable, the IOU's generation would be dispatched before the $30 energy from Supplier G. Under LMP, the locational price at C would reveal a $22/mwh locational cost to meet the next Megawatt of load at C in all hours. This price would be visible to both the IOU LSE and the FPSC. It is likely that either the IOU would recognize this opportunity to save further money for its retail customers or the FPSC would identify and appropriately inquire why the IOU was self-supplying 50% of needs at prices that exceed the locational price at Load C (reflecting the availability of cheaper supplies in the spot market).

LMP/FTR auctioning of energy clearly provides IOUs and other LSEs the access to the best buy in real time and the transparency of energy price signals to adjust their supply strategy. These examples have not chosen a situation where 100% of the supply was met through the spot market since market participants acknowledge that there are good business reasons why a certain amount of self-supply (either physically or financially) is prudent to hedge against risks. The critical aspect of LMP/FTR versus the GridFlorida approach is the degree of LSEs' access to competing supplies and transparency to economic opportunities. While the GridFlorida approach advertises "real time" imbalance dispatch, many aspects of its design will preclude IPP's or even other generation owned by IOUs, from having their units committed on-line in order to make this low strike price energy option available to Florida consumers. As a consequence, any price signal calculated will overstate the true potential for savings that exists. Market participants seek the LMP/FTR system to assure 'full' transparency of price and access by consumers to all generation.

NUMERICAL EXAMPLES DEMONSTRATING THE UNWORKABLE NATURE OF GRIDFLORIDA PROPOSED MARKET DESIGN AS WELL AS HIGHLIGHTING THE POTENTIAL FOR THE EXERCISE OF MARKET POWER.



GENERAL ASSUMPTIONS: (Same as prior numerical examples except for the addition of flowgates.)

At Point C:
A load withdraws its power at this point at a rate of 500MW each on-peak hour and 200MW's each off-peak hour.

At Point A:
A1 is a 200MW generator interconnected to point A with an incremental cost of $26/MWH.
A2 is a 300MW generator interconnected to point A with an incremental cost of $27/MWH.
G is an electric supply electrically interconnected to point A.

At Point B:
B1 is a 300MW generator interconnected to point B with an incremental cost of $22/MWH.
B2 is a 300MW generator interconnected to point B with an incremental cost of $23/MWH.

FGAC is the flowgate from point A to point C, normally rated at 600MW.
FGBA is the flowgate from point B to point A, normally rated at 100MW.
FGBC is the flowgate from point B to point C, normally rated at 400MW.

CASE 1 - Simplified – No congestion, no balanced schedule requirement, no interhour constraints affecting dispatch of generators (i.e. all generation can be scheduled for each hour and a generation schedule in one hour has no impact on any other hours).

	Morning Off-peak	Peak Hours	Evening Off-peak
Generator A1 – 26	0	0	0
Generator A2 – 27	0	0	0
Generator B1 – 22	200	300	200
Generator B2 – 23	0	200	0
Total Generation	200	500	200
Total Cost to Load C per hour	$4400	$11,200	$4400
Load @ C	200	500	200

CASE 1A – Everything else as in Case 1, but now consider the impact of adding a balanced schedule requirement. Assume that Generator B1 is not owned by or purchased by a Scheduling Coordinator ("SC") with load thus it cannot submit a balanced schedule. Also assume that Generator B2 is purchased by a SC with load in the forward market thus it can submit a balanced schedule. If B1 were to submit a schedule as balanced which would have the effect of overstating load, it would ultimately be exposed to a 20% imbalance tax in real time under GridFlorida's proposed tariff. Hence, B1's incremental cost and dispatch price would now be $26.40/mwh which accounts for the mark-up necessary to reflect true cost exposure.

	Morning Off-peak	Peak Hours	Evening Off-peak
Generator A1 – 26	0	**200**	0
Generator A2 – 27	0	0	0
Generator B1 – 22	0	**0**	0
Generator B2 – 23	200	300	200
Total Generation	200	500	200
Total Generation Cost per hour	$4600	$12,100	$4600
Increased Cost to Load C per hour	200 x ($23-22) = $200	300 x ($23-22) = $300 200 x (26-23) = $600 Total = $900	200 x ($23-22) = $200
Load @ C	200	500	200

There are two types of administrative withholding. The first is physical withholding which occurs as a result of prohibiting the RTO from accepting a generator-only schedule. The second is economic withholding, which occurs as a result of applying an imbalance tax to actual generation of an SC which exceeds its load obligations. The administrative withholding of B1's generation prevents the market from achieving the least cost possible and a higher cost is incurred by forcing a portion of Load C to be satisfied by higher cost A1. In the numerical example above, the imbalance tax premium would require a price for B1 which is greater than the price of A1. Hence, despite the greater efficiency and lower cost opportunity otherwise available through generation at B1, B1 will remain offline and administrative procedure will increase costs to consumers at C. In short, the proposed design does not assure reliability, encourages misstatement of load in order for the market to attempt to work despite the market rules and will artificially raise the market price of power either through forced withholding or through incorporation of imbalance tax premium in the dispatch price.

The LMP/FTR model does not employ a requirement that each entity's schedule be balanced either at the time of submittal, or in real time. Instead, it utilizes a day-ahead market to ensure that sufficient generation is started up and scheduled on line in order to assure a reliable generation schedule. In addition the LMP/FTR model allows LSEs to lock in day-ahead prices for generation from the spot market as a hedge against real time spot market prices. Day-ahead generation which clears in this day ahead auction process is subject to meeting its energy sale agreement and if generators that clear in the day ahead auction process subsequently face equipment problems, the generator can either prolong its time before taking an outage, shorten its offline time if an outage cannot be averted or

purchase energy in the real time auction process to honor its day-ahead auction sales obligations.

Case 1B – Everything else is as in Case 1, but now consider congestion and the impact of adding a physical transmission right based congestion management system such as the GridFlorida proposal. Assume that Load C has been allocated sufficient PTRs for FGAC to schedule its A1 and A2 generators. Assume also that B1 and B2 are merchant generators and Load C could save money for its consumers if it could buy from those units versus running A1 and A2.

Case 1B(i) – Further assume that PTR holders for FGBA and FGBC will not sell their PTRs even though the value of their schedule across those flowgates is less than the savings possible for Load C. This may occur simply because the initial absence of transparency obscures from PTR holders of FGBA and FGBC the opportunity for economic PTR sale. Also assume that no redispatch solutions exist to provide NPTR service. It should be noted that the absence of redispatch solutions could very well be due to withholding of decremental bids under the GridFlorida voluntary decremental bid submission proposal.

	Morning Off-peak	Peak Hours	Evening Off-peak
Generator A1 – 26	200	200	200
Generator A2 – 27	0	300	0
Generator B1 – 22	0	0	0
Generator B2 – 23	0	0	0
Total Generation	0	0	0
Total Generation Cost per hour	$5200	$13,300	$5200
Increased Cost to Load C per hour	200 x ($26-22) = $800	200 x ($26-22) = $800 100 x ($27-22) = $500 200 x ($27-23) $800 Total = $2100	200 x ($26-22) = $800
Load @ C	200	500	200

More efficient generation at B will be forced to be withheld through a combination of administrative procedure resulting from the inflexibility of physical rights market design and the ability of market participants to prevent efficient use of the grid by withholding the sale of PTRs that would otherwise facilitate a more efficient and valuable use of grid capacity. FGBA and FGBC PTR holders do not see the opportunity to sell PTRs immediately because there is insufficient price transparency.

Under the LMP/FTR model, withholding of transmission capability is simply not possible. The RTO considers all self-schedule requests and the concomitant decremental prices and all generation not scheduled at its offered price, and utilizes its least cost software to perform the auction clearing process considering all of the system constraints and security limits that exist in real time. Grid efficiency and reliability is maximized and locational energy prices are transparent.

Case 1B(ii) – Further assume that after a period of time, PTR holders for FGBA and FGBC see that there is an opportunity to make more money by the sale of PTRs. At what price will a PTR holder seek to sell Load C access to generation at location B? Ideally, the PTR holder will sell the set of PTRs for all three periods for \$3697, that is, \$1 less for the applicable periods PTRs than Load C's increased cost for such periods (PTR charge \$799 + \$2099 + \$799) in the absence of PTRs to facilitate the purchase/scheduling of more economic generation. If Load C had to purchase FGBA PTRs from an entity different from the holder of FGBC PTRs, it is possible they may ultimately pay more than the \$3697. This could occur because the purchase price for FGBA PTRs becomes sunk once executed (PTRs have no value if they are not used for scheduling), yet scheduling cannot be achieved without the subsequent purchase of FGBC PTRs. If the seller of those PTRs becomes aware of the strategic need for its PTRs, it can cause Load

C to pay more for the set of FGBA and FGBC PTRs than they are worth to Load C in hindsight. The PTR holder will get most of the savings available to Load C despite the fact that the cost of congestion will likely be significantly less than the differential in incremental costs at A versus those at B. This is because full output operation of generation at B does not exceed the flowgate capabilities and hence congestion will only exist to the extent that other low priced generation schedules induce additional network flows over those flowgates. It is most likely that the congestion cost would be far less than the congestion rents that could be demanded under the PTR model.

	Morning Off-peak	Peak Hours	Evening Off-peak
Generator A1 –26	0	0	0
Generator A2 – 27	0	0	0
Generator B1 – 22	200	300	200
Generator B2 - 23	0	200	0
Total Generation	200	500	200
Total Cost to Load C per hour for generation	$4400	$11,200	$4400
Increased Cost to Load C per hour due to price demanded for PTRs	$799	$2099	$799
Total Cost to Load C per hour	$5199	$13,299	$5199
Load @ C	200	500	200

More efficient generation at B will not be withheld, but Load C will not see much savings since the PTR holders can demand compensation for PTRs that far exceed the true congestion cost or their lost opportunity cost.

Under the LMP/FTR model, generation at B also would not be withheld and Load C would only be exposed to the true costs of congestion to achieve its delivery. The true costs of congestion are the locational price differential between the locational energy price at B and the locational energy price at C. In this case, the off-peak price would be $22/mwh at C, $22/mwh at B and $22/mwh at A since there

is no congestion. The FTR holder does not deserve any compensation since the holder could buy energy located at B as if it were located at A or C. The FTR holder has the congestion right to assure delivered price, but does not have the right to constrain physical delivery. In the on-peak period, both FGBA and FGBC will be at their limits and the price of the next megawatt ("MW") at C will be at or below the price of A1, possibly due to lower cost generation being available from the rest of the network through interconnects at point A. If the price at C is set by A1, the FTR value of each MW of FGBC and FGBA FTRs would be equal to $26 - $23 or $3/mwh. FTR holders would receive $1500 for each hour of the on-peak period versus the $2100 they could extract through threat of withholding physical congestion rights. Consumers at C benefit from this competitive efficiency and avoid paying windfall profits of $600 additional premium under this PTR example.

Case 2A – Everything else is as in Case 1, but now consider the impact of taking into account the real life operating constraints of generators. Assume A1, A2, B1, B2 must remain on-line and generating no lower than 100MW for at least two consecutive periods (on-peak and off-peak) if started.

	Morning Off-peak	Peak Hours	Evening Off-peak
Generator A1 – 26	0	0	0
Generator A2 – 27	0	0	0
Generator B1 – 22	200	300	100
Generator B2 – 23	0	200	100
Total Generation	200	500	200
Total Cost to Load C per hour	$4400	$11,200	$4500
Increased Cost to Load C per hour	$0	$0	$100
Load @ C	200	500	200

Case 2B – Everything else as in Case 1, but now also consider (i) a real world constraint that A1, A2 and B2 require at least 60 minutes between the request and the ability to deliver output and (ii) the impact of adding a balanced schedule requirement. Assume that Generator B2 is not owned by or purchased by a SC with load thus it cannot submit a balanced schedule but Generator B1 is purchased by a SC with load in the forward market thus it can submit a balanced schedule. Load C does not know it needs to buy replacement power until it hits the on-peak period and at that time it is not possible to start A1, A2, or B2 due to start-up time requirements for the type of generation to meet the need for that period. The only available power is purchased from Supplier G at Point A.

	Morning Off-peak	Peak Hours	Evening Off-peak
Generator A1 – 26	0	0	0
Generator A2 – 27	0	0	0
Generator B1 – 22	200	300	200
Generator B2 – 23	0	0	0
Supplier G –		200	
Total Generation	200	500	200
Increased Cost to Load C per hour	$0	$ G can charge, 20% above avoided imbalance charge arising from future redispatch (see below)	$0
Total Cost to Load C per hour	$4400	$6,600 plus what $ G can charge, 20% above avoided imbalance charge arising from future redispatch (see below)	$4400
Load @ C	200	500	200

G can charge a premium of up to 20% (the imbalance tax!) beyond whatever risk premiums exist regarding the bilateral sale of power delivered in a future period. The 20% premium reflects a windfall profit to Supplier G and market inefficiency.

The LMP/FTR model does not employ a requirement that each entity's schedule must be balanced either at the time of submittal, or in real time. Instead, it

utilizes a day-ahead market to ensure that sufficient generation is started up and scheduled on line in order to assure a reliable generation schedule. It assures that the aggregate generation is in balance with the aggregate demand subject to system security constraints. The LMP/FTR model simultaneously considers all generating unit constraints and other security constraints, an optimization no individual market participant or collective set of individual market decisions can accomplish without access to competitive market information of others. It is not possible for the sum of market participants' schedules which are necessarily based on their incomplete knowledge of system conditions and supply prices under a balanced schedule requirement approach to match the efficiency of an RTO auction clearing process.

Case 3 - Everything else as in Case 1, but now consider congestion and the impact of adding a physical transmission right based congestion management system such as has been proposed for GridFlorida. Assume that all injections at A flow only across flowgate FGAC and that Load C has been allocated sufficient PTRs over FGAC to schedule its A1 and A2 generators. Further assume B1 & B2 are merchant generators and Load C could save money for its consumers by buying from those units versus running A1 and A2. Assume that all injections at B flow 1/5th over flowgate FGBA and 4/5th over flowgate FGBC.

Case 3B(i) – Further, PTR holders of FGBA and FGBC refuse to sell their PTRs even though the value of their schedule across those flowgates is less than the savings possible for Load C. This is because the initial absence of transparency obscures PTR holders' of FGBA and FGBC opportunity for economic PTR sale. No redispatch solutions exist to provide NPTR service.

	Morning Off-peak	Peak Hours	Evening Off-peak
Generator A1 – 26	200	200	200
Generator A2 – 27	0	300	0
Generator B1 – 22	0	0	0
Generator B2 – 23	0	0	0
Total Generation	0	0	0
Total Cost to Load C per hour	$5200	$13,300	$5200
Lost opportunity to buy cheaper energy for Load C per hour	200 x ($26-22) = $800 less true congestion costs	200 x ($26-22) = $800 100 x ($27-22) = $500 200 x ($27-23) $800 Total = $2100less true congestion costs	200 x ($26-22) = $800less true congestion costs
Load @ C	200	500	200

More efficient generation at B is withheld through a combination of administrative procedure resulting from the inflexibility of physical right market design and the ability of market participants to prevent efficient use of the grid by withholding the sale of PTRs for a more efficient and valuable use of grid capacity. FGBA and FGBC PTR holders do not see the opportunity to sell PTRs immediately because there is insufficient price transparency. In addition, it is not necessary for PTR holders to refuse to sell both FGBA or FGBC PTRs. This same result could occur if *either* FGBA or FGBC PTRs were withheld since generation schedules at B would require a complete set of flowgates ($1/5^{th}$ FGBA and $4/5^{th}$ FGBC) in order to be accepted in the absence of redispatch solutions.

Under the LMP/FTR model, FTRs do not constrain the RTO's evaluation of schedules and dispatch of the system and all injections have associated prices including backdown prices for self-schedules. The RTO dispatch of the system would yield the most efficient system dispatch and generation at B would be dispatched if the impact on the aggregate system costs (redispatch) was less than the benefit it provides through economic energy.

Case 3B(ii) – Assume that after a period of time, PTR holders for FGBA and FGBC see that there is an opportunity to make more money by sale of their PTRs. At what price will a PTR holder seek to sell Load C access to generation at B? Eventually, the price for the set of PTRs for all three periods will rise to $3697 (i.e. $1 less for the applicable period's PTR than Load C's increased cost for such period (PTR charge $799 + $2099 + $799). As in the earlier case, 1B(ii), the price could be even higher where PTR purchases must be made with multiple parties in order to get the full set of PTRs for a given desired schedule. The PTR holders will get most of the savings available to Load C since they can prevent access to more efficient generation.

	Morning Off-peak	Peak Hours	Evening Off-peak
Generator A1 – 26	0	0	0
Generator A2 – 27	0	0	0
Generator B1 – 22	0	200	0
Generator B2 – 23	200	300	200
Total Generation	200	500	200
Total Cost to Load C per hour for generation	$4400	$11,200	$4400
Increased Cost to Load C per hour due to price demanded for PTRs	$799	$2099	$799
Total Cost to Load C per hour	$5199	$13,299	$5199
Load @ C	200	500	200

More efficient generation at B will not be withheld, but Load C will not see much of the efficiency savings since the PTR holders can manipulate the market.

Under the LMP/FTR model, FTR holders cannot force withholding of any generation. FTR holders will get paid the locational price differential for that flowgate represented by the difference between the energy price at C or A (if FGBC FTR or FGBA FTR, respectively) and the dispatch solution will provide for the

most efficient use of the grid and the least cost to meet aggregate demand. In this case, the off-peak price would be $22/mwh at C, $22/mwh at B and $22/mwh at A. The FTRs do not need to payout any value since there is no congestion and the holder could buy energy located at B as if it were located at A or C – it has the congestion right to assure delivered price, but does not have the right to constrain physical delivery. In the on-peak period, both FGBA and FGBC are at their limits and the price of the next MW at C is at the price of A1 (or possibly lower from the rest of the network available through interconnect at point A). If the price is set by A1, the FTR value of each MW of FGBC and FGBA FTRs would be equal to $26 - $23 or $3/mwh. FTR holders would receive $1500 for the on peak period versus the $2100 they could extract through threat of withholding. Consumers at C benefit from this competitive efficiency for the $600 balance.

In sum, it is clear that the LMP/FTR model is superior to that proposed by the GridFlorida Applicants in several important ways. LMP/FTR provides superior LSE access to most economic supplies and transparency of prices by location. In addition, LMP/FTR assures the most efficient system operation to satisfy aggregate demand and provides for allocation of costs to those who cause them to be incurred. By contrast, the PTR based approach is inherently inefficient, impedes LSEs' ability to identify and access lower cost supply options and provides opportunities for market power abuse. Joint Commenters agree that the markets should not be permitted to function until market power has been addressed. [Tr. 47]. As it is presently written, the market design will permit incumbent utilities or their affiliates the ability to deny physical market access or extract monopoly rents in return for such access. The incumbents will assume control over the energy market, run the regulation ancillary service market and profit from socialization of pricing while remaining undetected due to the lack of transparency. [Tr. 154]. To remedy the problem, Joint Commenters propose that the independent Board of Directors and the Market Monitor be chosen as soon as possible and that market design analysis should continue in *pari materia* with the ongoing FERC rulemaking process.

III. Issues Raised at the May 29 Workshop

Several issues were raised at the May 29 Workshop that the Joint Commenters feel need additional elaboration. To the extent possible, the issues are set forth in context.

A. Refunds.

The representative from Seminole Electric Cooperative expressed the belief that remedies, and in particular, refunds are necessary in order to address the market power issue.

> MR. MILLER: We also think remedies are important. You should consider the necessity for refunds because nothing makes people wake up more quickly in terms of bad acts than the potential for refunds. The extent to which marketers are fighting refunds in the west, I think, underscores that fact. [Tr. 47]

As previously stated, Joint Commenters unequivocally agree that market power must be addressed. However, Joint Commenters do not agree that refunds are the best mechanism to do so, and urge the FPSC as an alternative, to require transparent pricing to assure competitive outcomes or identify the need for immediate corrective action where design flaws are identified. For the reasons stated below, a refund obligation should not be included as part of the GridFlorida market design. Refunds will likely lead to a number of negative consequences for the GridFlorida market, for new investment in that market and ultimately for consumers. Two points are worth noting with regard to the possibility of refunds. First, is that if employed, they will be set at the wrong level since no individual is capable of retrospectively determining what the correct market price should have been. Second, if that option exists, those who serve to benefit from interference (even where the market is functioning well) in the market will promote intervention. Negative consequences may include an increase in the level of risk for suppliers and investors, a decrease in liquidity, and increased litigation costs. For example, the inevitable result of injecting a significant source of regulatory uncertainty and additional risk on all market transactions will be an increase in the cost of financing new generation, an increase in the cost of trading of bulk power, and ultimately an increase in the price of bulk power. Bulk power sellers may increase their prices to adjust for the increase in financial risk associated with their increased exposure to the possibility of after-the-fact revisions of commercially negotiated prices. Likewise, developers may be reluctant to invest if there is the possibility that the prices upon which their investment decisions are being made will be reduced due to regulatory intervention. In short, Joint Commenters submit that there are adequate provisions in existing law with respect to refunds and encourage the FPSE to seek other alternatives for the mitigation of market power than refunds which will have a predictable negative impact on the GridFlorida market.

B. Planning.

Pursuant to direction given at the May 29 Workshop, [Tr. 233] Applicants sponsored a collaborative telephone conference call on June 11, 2002 to discuss market participants' planning comments. Joint Commenters submitted their planning comments to the Applicants in advance of the call and attended the call. On June 14, the revised Planning Protocol was forwarded by the Applicants to the Advisory Committee. Most of the Joint Commenters' concerns have not been addressed by the Applicants. Joint

Commenters continuing primary concerns with the Planning Protocol may be summarized as follows:

1. Changes to the Planning Protocol Are Unjustified

In general, even taking into account Applicants June 14 revisions to the Planning Protocol, the extensive changes to the Protocol create over-reliance on Participating Owners ("POs") decision-making control. The changes are not justified by the move to an ISO structure. A true collaborative is vital to assuring that the full spectrum of planning solutions are considered and that the very best standards are developed for the region, not just those that benefit a single class of users. The Applicants should be ordered to replace the instant Protocol with the mark-up of the Planning Protocol proposed by the Florida Municipal Power Agency on June 6, 2002. In the alternative, the Applicants should be ordered to amend the Planning Protocol as set forth herein.

2. Planning Responsibilities of POs Undermine Independence

In general, POs are elevated above all other stakeholders and access to information by all other stakeholders has been decreased under the instant proposal. Too much of the planning responsibilities remain in the control of the POs. Instead, the RTO should be responsible for all planning functions and POs should provide input. In addition, the RTO should perform planning studies or hire consultants to do so.

Joint Commenters have identified five specific areas in which the planning responsibilities of POs undermine RTO independence. First, under proposed new Section V, Evaluation of Transmission Service Requests, the RTO is *required* to include POs in the process. This requirement forces the RTO to include entities it may or may not need to perform its evaluation. The section should state: "In order to carry out this function, the POs shall agree to provide the level of consulting assistance requested by the Transmission Provider." Second, under proposed new Section VII, Development of GridFlorida Transmission Plan, the RTO seems obligated only to satisfy the long-term Point-To-Point obligations of POs and not other market participants. This should be uniform. Third, the insertion of "and POs" in proposed new Section VII is inappropriate and should be removed. The RTO should have ultimate control over the selection of facility expansion. Fourth, it is not clear under proposed new Section VII why POs' existing ten-year plans should be adopted immediately by the RTO. The RTO should have the flexibility to evaluate projects outside the 4-10 year lead time. Finally, the quantity and quality of information to be made available to stakeholders has been inappropriately reduced under Section I. Clarification should be added to the effect that documents explaining the analysis and the study itself should be available, not just the supporting assumptions.

3. Construction of Facilities Identified by GridFlorida, Proposed New Section VIII

This section continues to be a primary concern of Joint Commenters. In general, the construction of facilities identified as part of the GridFlorida Plan is left to the PO. This section suffers from the same infirmities that plague capacity selection in this state. Unchecked self-selection will negate meaningful cost-effectiveness evaluation. Facility construction should be a two-step process. Joint Commenters propose the following protocol:

a. First, determine whether generation or transmission construction is the least cost alternative.

b. Second, if transmission is the most cost-effective alternative, a competitive bidding process including the PO and any market participant with an independent evaluator should be utilized.

c. The primary components of competitive selection process should be:

- The RTO develops the request for proposal ("RFP") package.

- The RTO will select a neutral third party to score the proposals.

- Copies of the RFP package and the selection of the third party evaluator will be supplied to the FPSE.

- All potential bidders who have secured the RFP package will have a specified period of time in which to object to either the criteria set forth in the RFP package or the third party evaluator.

- If an objection is received, the FPSC shall conduct an expedited proceeding to resolve the disputed issues.

- All bids, including that of the affected POs, are submitted to the third party evaluator.

- The third party evaluator applies the criteria and ranks the proposals.

- Whichever entity is selected is bound by the terms of the RFP and its bid.

C. Price Spikes

The representative from Clay Electric Cooperative expressed concern regarding price spikes occurring in conjunction with the GridFlorida market design becoming operational.

> MR. DYAL: All I know simply right now is I'm not paying congestion management. If I am, it is socialized or somewhere I don't see it. And what we were asking is as you start up these markets and as you start dealing with congestion management, that we make sure that there is protection or market things in place that would avoid any cost spiking that would occur due to congestion management. We have seen it in other markets where this has occurred, where they have put markets in and all of a sudden we have got price spikes due to congestion management. [Tr. 67-68]

Joint Commenters share Clay Electric Cooperative's concern about price spikes but submit that with a proper LMP/FTR market design, not only should price spikes be less likely to occur than under the current regime, the magnitude of price spikes should also be blunted by the transparent, objective price signals of LMP.[1] Competitively healthy price spikes generally arise from: (1) increased power production cost increases such as fuel price increases and emission credit cost increases; and (2) scarce resources pushed to the limit by low reserve margins, unplanned outages, significant weather changes and increased demand. Price spikes could arise from the exercise of market power such as economic or physical withholding or inadequate market design mechanisms such as a lack of forward contracting and lack of demand responsiveness. The difference, as Mr. Dyal suggests, is that price spikes are, for the most part, socialized to all ratepayers as a result of generation costs being averaged.[2] Under LMP, price spikes will be transparent and attributed to their sources. Moreover, RTO, not market participant, management of access into and across the transmission system will assure least cost solutions and highlight opportunities for further competitive entry.

D. Attachment T, Existing Transmission Agreements

Joint Commenters wish to clarify an exchange that occurred during the May 29 Workshop regarding the December 15, 2000 demarcation date for new facility construction not being subject to rate pancaking. In response to a query from Chairman Jaber regarding ongoing discussions between Calpine and the Applicants to remedy the demarcation issue, the representative from Calpine responded as follows:

> MR. REGNERY: Yes, we are. This is an, this is an absolute vital position associated with Calpine and its contract with Seminole and Seminole's position with respect to its purchase, its current purchase of megawatts out of our Osprey Power Plant. [Tr. 185]

---

[1] It has been determined that one of the causes of the summer of 1998 price spikes in the Midwest was a lack of objective price information. Systematic, contemporary information is required for market participants to make rational decisions. Staff Report to the Federal Regulatory Commission on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998, Sept. 22, 1998, pgs 4-3 - 4-4.

[2] The only consistent indicia of cost variations under the current regime is the pass through of fuel and purchased power costs through the cost recovery clause.

It should be clarified that there are no ongoing discussions with TECO or any of the Applicants on this issue. Rather, there is an ongoing proceeding at the FERC, Docket No. ER02-1663, wherein Calpine and Seminole have filed protests to TECO's refusal to execute a transmission service agreement that provides that there will be no rate pancaking for the Osprey facility when Seminole designates it as a network resource in June of 2004. Joint Commenters reiterate their request that this Commission find Applicants' change of the demarcation date for new facilities to be in excess of that which was necessary to comply with the Commission's December 20 Order and order the change to be withdrawn.

E. Attachment W - ICE Specification

The representative for the Florida Municipal Group had some specific negative comments regarding an ICE proposal that Joint Commenters wish to dispel. The comments were as follows:

> MR. JOHN: In terms of the ICE, the install [sic] capacity requirement that is rather vaguely developed here in the pleading and has been from the beginning, our view is that is an area that's fraught with room for mischief. We tend to think that the historical approach of having this Commission and the FRCC together decide what is appropriate in terms of long-term reserve requirements is the right way to go for the foreseeable future. So we are suspicious, frankly, of an ICE or an ICAP requirement voluntarily being adopted down here. [Tr. 108]

In their Pre-Workshop Comments, Joint Commenters expressed their support for a mechanism to assure payment for capacity services required of generators. Installed capacity markets should be considered as part of the initial GridFlorida market design because it will ensure that the transition to a competitive market will not adversely affect reliability. Joint Commenters urged that the development of the capacity requirement and associated generator obligations should be performed in conjunction with an ongoing stakeholder process. In addition, Joint Commenters proposed a transition mechanism to avoid imposing an immediate, inflexible RTO capacity obligation on LSEs that currently do not meet the standard. Joint Commenters reiterate the need for analysis and development of rational installed capacity markets.

F. Capacity Benefit Margins

JEA expressed concern over the preservation of its approximately 375 megawatt capacity benefit margin ("CBM") from the Georgia Integrated Transmission System to JEA. JEA's concern is that it is not certain how GridFlorida will allocate PTRs for the CBM.

> MR PARA: So that -- and so what the CBM does is it reserves some of the capacity that our customers paid for and our customers own so that we can use that to provide, to buy capacity and energy from every place except for Florida basically.
>
> Our position is that physical transmission rights should be allocated to JEA equal to our capacity benefit margin at the Florida/Georgia interface. And as I said, I believe this is a JEA-specific item. [Tr. 125]

Joint Commenters believe that in some instances, inter-regional transfer capabilities between transmission service providers have been over-reserved in the name of supporting native load requirements. The benefits of CBM can only accrue when the transmission service provider has the ability to actually use the reserved capacity. When that ability does not exist, CBM should not be fully sustained by the FPSC, and the creation of a "parking" effect should be regulated and severely constrained. The primary impact of CBM is a restriction on the degree of access aggregate Florida demand has to competing generation supplies outside of Florida. Optionality benefits are also destroyed. CBM creates preferences where vertically integrated service from the local utility exist that can be exploited by regulated utilities and their affiliates.

G. Use It or Lose It - Recallable Transmission Rights

During their rebuttal to Workshop presentations, Applicants responded to the Joint Commenters' analysis that PTRs provides the potential for hoarding of rights to the detriment of non-incumbent market participants. The Applicants stated:

> MR. NAEVE: There was a suggestion that if you do that (allocate rights based on historic use), the recipients of those transmission rights will have no incentive to make them available to other parties when they're not using them, and there also was a suggestion that they might be able to physically withhold transmission rights from the system. And I'd like to respond to both of those.
>
> First, I think if you're allocated a valuable right and you are not going to need it, I think you have a significant financial incentive to try to capitalize on that valuable asset that would otherwise wither away. And indeed, under the proposal we've made, if you do not schedule that right, the right is allocated to third parties, and the -- or auctioned to third parties, and the proceeds for the auction don't go to you....
>
> And then on the withholding point, that very same provision also addresses withholding. You can't withhold it. If you're not going to use it, then it's going to be auctioned off by the RTO. [Tr. 217-218]

Joint Commenters acknowledge the Applicants response, however, respectfully disagree. The Applicants' proposal to make all PTRs sold in the "use it or lose it" auction subject to recall two hours prior to real time will inhibit or negate the value of this feature of the secondary market. Further, Applicants' proposal provides only hour by hour confirmation of schedules yet most generators have operating characteristics that affect multiple hours. Whether or not the two hour periods were expanded to four or more hours, the simple matter is that merchant generators would be impeded in scheduling start-up of their units when confirmation of NPTR and NDBTS does not occur until 30 minutes in advance of the hour and such confirmation is only for the next hour. Market participants need certainty that they can complete transactions they enter into, and therefore, the ability of PTR holders to recall RTRs two hours before a transaction is to occur is virtually useless. The recall right also will impede hedging of risk in trading markets, and open the door to gaming and anticompetitive conduct. Such a recall feature for PTRs should be prohibited, as it violates the Federal Energy Regulatory Commission's ("FERC's") determination in Order No. 2000 (at 31,127) that "a workable market approach to congestion management should establish clear and tradable rights for transmission usage, promote efficient regional dispatch, support the emergence of secondary markets for transmission rights, and provide market participants with the opportunity to hedge locational differences in energy prices." As the Applicants have opined in previous filings, allowing the PTRs to be recallable is necessary because if PTR holders knew they could not recall the PTRs, they would simply schedule more transactions in the day-ahead market than they really need as a means of preserving flexibility and meeting unanticipated needs. As such, rather than being sold in the "use it or lose it" auction, the Applicants have affirmed that PTRs would not become available until the very last moment when it became clear the PTR was not needed. This would render the PTR of limited or no use to market participants. Joint Commenters believe that this "solution" designed to increase the amount of PTRs available in the secondary market does not address the real problem. The problem centers on the ability and incentive of PTR holders to make fictitious PTR schedules for capacity they do not intend to utilize, such as to meet "projected" native load service requirements. Furthermore, the recallable nature of RTRs may not even address the problem of fictitious schedules, as PTR holders will have an incentive to schedule more PTRs than they need. For example, PTR holders do not have any financial incentive to allow their PTRs to fall into the "use it or lose it" auction. Therefore, PTR holders may seek to eliminate their competitors' access to PTRs by fictitiously scheduling them, thereby ensuring that the PTRs will not become available until it is too late for the PTRs to be of use to others.

IV. Request for Hearing and Preliminary List of Disputed Issues of Material Fact and Policy Issues

Joint Commenters applaud the progress that has been made to date with respect to the various iterations of the GridFlorida RTO. Much has been accomplished during the collaborative process and Phase I of these proceedings. Notwithstanding the positive progress, Joint Commenters reaffirm that many, many issues of fact and policy remain to be fully and fairly vetted by this Commission. In many subject matter areas, the only record developed in this proceeding is that of the compliance filing itself. No comments have been received, nor testimony given on numerous areas of the OATT, the Market Monitor and many other aspects of this voluminous filing. Depending on what further action the Commission decides to take with respect to holding Generator Interconnection Service and Market Design analysis in abeyance pending the resolution of the FERC's ongoing rulemaking proceedings on these issues, disputed issues of material fact may include:

1. Is the GridFlorida Board Selection Committee weighted in favor of the investor-owned utilities?

2. If the composition of the GridFlorida Board Selection Committee is weighted in favor of investor-owned utilities, what should the composition of the Board Selection Committee be?

3. Is the GridFlorida decision-making process independent of control by any single market participant or class of market participants?

4. Are checks and balances or reporting requirements necessary to assure accountability of the Board of Directors, or any Committees appointed thereby, when these bodies are not meeting in the open because they are not 'in the decision-making mode'? [TR 27, 15-18]

5. Section 2.1.1(j) of the GridFlorida Information Policy has been amended by the Applicants to require only that 'significant' actions taken by GridFlorida as the Security Coordinator will be subject to the pubic information policies. How is this amendment justified by the change to an Independent System Operator, who determines what 'significant' actions are and should the Public Service Commission order the Applicants to delete this limitation?

6. Should the Board Selection Committee, rather than the Applicants, cause the slate of candidates for the Board of Directors to be elected or named as initial directors and designate the classes of directors?

7. Should the stakeholder Advisory Committee vote on the compensation to be paid to directors?

8. Does the GridFlorida proposal allow for appropriate flexibility to modify the documents in the future?

9. Does the GridFlorida Advisory Committee have adequate access to the GridFlorida Board of Directors to present majority and minority views of market participants to ensure that there is a full and fair vetting of all issues?

10. Are the executive session exceptions to the GridFlorida Board of Directors open meeting requirement too broad? What should the parameters for declaring an executive session be?

11. Do the committees to be established by the Board of Directors have the delegated power of the Board of Directors in the management and business of GridFlorida, and if so, do the same open meeting and procedural requirements apply to the committees?

12. Should a competitive bid requirement be applied to market participants who provide goods and services to GridFlorida?

13. Should GridFlorida adopt incentive ratemaking or other specific performance incentives for the RTO?

14. Is the five-year opt out of zonal rates for bundled retail load appropriate?

15. Does the GridFlorida market design provide for an imbalance penalty, and if so, is such a penalty appropriate?

16. Can a balanced schedule requirement be meaningfully enforced?

17. Will the operation of "hierarchical" control areas within GridFlorida yield the same level of independence and operational market efficiencies as a single control area operated by the GridFlorida independent system operator?

18. Does the GridFlorida physical transmission rights model provide opportunities for the exercise of market power?

19. What entities currently possess regional or local market power in the GridFlorida region?

20. Should the Commission initially implement the GridFlorida filing, as modified pursuant to these proceedings, except for a detailed market design and generator interconnection protocols, until after the FERC's Standard Market Design and Generator Interconnection Service proceedings have concluded?

21. Is it anticipated that the number and location of flowgates identified in the GridFlorida region will remain static or will those designations change over time and how would changes impact implementation of the physical transmission rights model?

22. If GridFlorida adopts a market design different from that of the rest of the region, will that adversely affect GridFlorida's ability to interface with and benefit from access to the rest of the region?

23. Which market design model is the most likely to result in the least-cost generation being dispatched to the largest number of customers?

24. Which market design model best optimizes decisions as to whether transmission infrastructure is enhanced or new generation is built?

25. In the planning and operations protocols, has adequate consideration been given to the use of demand side options and generation alternatives when GridFlorida is identifying needed expansion and maintaining reliability?

26. Does the proposed GridFlorida market design assure independence of the transmission system operation?

27. Does the proposed GridFlorida market design promote the inefficient use of the existing transmission system capabilities?

28. Does the proposed GridFlorida market design discriminate against some network customers and some types of generators?

29. Does the proposed GridFlorida market design facilitate the exercise of market power?

30. Is the proposed GridFlorida market design workable?

31. Does the provision for Scheduling Coordinators who are not the RTO, but rather a limited class of market participants, to act as the Balancing Authority critically compromise the independence of the RTO?

32. Do the liberal provisions regarding safe harbor leases in OATT, Attachment O, Section I.A.3 compromise the independence of the RTO?

33. Do certain GridFlorida funding provisions such as compensation from the Florida Reliability Coordinating Council for Security Coordinator activities

pursuant to OATT Attachment O, Section I.B adversely impact the independence of the RTO?

34. Is it appropriate for disputes regarding line ratings of a transmission system facility to be referred to the Transmission Planning Committee pursuant to Attachment O, Section II, instead of GridFlorida having final decision-making control?

35. Should decisions on all policy, operation and planning matters include all stakeholders or just Participating Owners as provided for in OATT Attachment O, Section III?

36. Is it appropriate for the GridFlorida tariff to obligate merchant generators that are not sold as capacity to Load Serving Entities to provide capacity services absent compensation?

37. What effect does the deletion the Planning Bill of Rights from the RTO Formation Plan have on GridFlorida's planning functions?

38. Does GridFlorida OATT Attachment N place too much reliance on Participating Owners' decision-making control and does this undermine the effectiveness and independence of the RTO?

39. Should facility construction be a two-step process that first evaluates cost-effectiveness of generation solutions as compared to transmission solutions and rationally decides between the two?

40. Should a competitive bidding process that utilizes a neutral third party to conduct and evaluate bids of all participants be used instead of the self-selection provisions contained in Attachment N?

41. Do price spikes currently occur on the Florida grid and, if so, what are the causes of the spikes and how are the costs accounted for?

42. Should the Public Service Commission order the Applicants to reinstate the December 15, 2000 demarcation date for facility construction exemption from rate pancaking?

43. Should the GridFlorida proposal include an ICE Specification to ensure the development of rational installed capacity markets with an appropriate transition mechanism?

44. Should the Capacity Benefit Margin at the Florida/Georgia interface be retained?

45. Do PTR holders have the ability and incentive to horde PTRs and make fictitious PTR schedules for capacity they do not intend to utilize in order to

ensure that the PTRs will not become available until it is too late for the PTR to be utilized by other market participants?

46. Is the reservation of rights with respect to Third Party Agreements as set forth in the Participating Owners Management Agreement too broad?

47. Does the Participating Owners Management Agreement permit Participating Owners to earn more than just a reasonable rate of return and recover more than the capital cost invested in their controlled Facilities?

The foregoing issues provide the FPSC with a preliminary indicium of matters still to be resolved. This list is not intended to be exhaustive - merely illustrative. The FPSC is respectfully requested to proceed to formal, evidentiary hearing in order to afford parties the full panoply of procedural and substantive due process rights on these monumentally important matters.

Respectfully submitted this 21st day of June, 2002.

Leslie J. Paugh
Leslie J. Paugh, P.A.
2473 Care Drive, Suite 3, 32308
Post Office Box 16069, 32317-6069
Tallahassee, Florida
Telephone: 850-656-3411
Telecopier: 850-656-7040
lpaugh@paugh-law.com

Attorney for: Calpine Corporation,
Mirant Americas Development, Inc.
Duke Energy North America, LLC

CERTIFICATE OF SERVICE
DOCKET NO. 020233

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by hand-delivery (*), facsimile (**), or U.S. Mail, to the following parties on this 21st day of June, 2002.

William Keating, Esq. *
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Lee E. Barrett
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Mark Sundback, Esq.
Kenneth Wiseman, Esq.
Andrews & Kurth Law Firm
1701 Pennsylvania Ave., NW
Suite 300
Washington, DC 20006

David L. Cruthirds, Esq.
Attorney for Dynegy, Inc.
1000 Louisana Street
Suite 5800
Houston, TX 77002-5050

Lee L. Willis, Esq. *
James D. Beasley, Esq.
Ausley & McMullen Law Firm
227 South Calhoun Street
Tallahassee, FL 32301

Michelle Hershel
Florida Electric Cooperatives Association, Inc.
2916 Apalachee Parkway
Tallahassee, FL 32301

Thomas W. Kaslow
Calpine Corporation
The Pilot House, 2nd Floor
Lewis Wharf
Boston, MA 02110

Bruce May, Esq.
Holland & Knight Law Firm
Bank of America
315 South Calhoun Street
Tallahassee, FL 32302-0810

John W. McWhirter, Esq.
McWhirter Reeves
400 North Tampa Street
Suite 2450
Tampa, FL 33601-3350

David Owen, Esq.
Assistant County Attorney
Lee County, Florida
P.O. Box 398
Ft. Myers, FL 33902

Frederick M. Bryant
FMPA
2061-2 Delta Way
Tallahassee, FL 32303

Joseph A. McGlothlin, Esq.
McWhirter Reeves
117 S. Gadsden Street
Tallahassee, FL 32301

Michael B. Twomey, Esq.
P.O. Box 5256
Tallahassee, FL 32314-5256

John Attaway
Publix Supermarkets, Inc.
P.O. Box 32015
Lakeland, FL 33802-2018

Natalie B. Futch
Bill Bryant, Jr.
Katz, Kutter
106 E. College Avenue
12th Floor
Tallahassee, FL 32301

Pete Koikos
City of Tallahassee
100 West Virginia Street
Fifth Floor
Tallahassee, FL 32301

Ed Regan
Gainesville Regional Utility Authority
P.O. Box 147117, Station A136
Gainesville, FL 32614-7117

Douglas John
Matthew Rick
John & Hengerer
1200 17th Street, N.W.
Suite 600
Washington, DC 20036-3013

Reedy Creek Improvement District
P.O. Box 10170
Lake Buena Vista, FL 32830

Ron LaFace/Seann M. Fraizer
Greenberg, Traurig Law Firm
101 E. College Avenue
Tallahassee, FL 32301

Wade Litchfield
Office of General Counsel
700 Universe Boulevard
Juno Beach, FL 33408-0420

Paul Lewis, Jr.
Florida Power Corporation
106 E. College Avenue, Suite 800
Tallahassee, FL 32301-7740

Marchris Robinson
Manager, State Government Affairs
Enron Corporation
1400 Smith Street
Houston, TX 77002-7361

Florida Retail Federation
100 E. Jefferson Street, Suite 900
Tallahassee, FL 32301

Daniel Frank, Esq.
Sutherland, Asbill & Brennan
1275 Pennsylvania Ave., N.W.
Washington, DC 20004-2415

Robert Miller
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, FL 32746

Paul Elwing
Lakeland Electric
501 East Lemon Street
Lakeland, FL 33801-5079

Alan J. Statman
General Counsel
Trans-Elect, Inc.
1200 G. Street, N.W., Suite 600
Washington, DC 20005

Thomas J. Maida
N. Wes Strickland
Foley & Lardner Law Firm
106 E. College Avenue, Suite 900
Tallahassee, FL 32301

Harry W. Long
Angela Llewellyn
Tampa Electric Company
P. O. Box 111
Tampa, FL 33601

Jack Shreve
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Suite 812
Tallahassee, FL 32399-1400

Michael Briggs
Reliant Energy Power.
Generation, Inc
801 Pennsylvania Avenue, Suite 620
Washington, DC 20004

James A. McGee, Esq. **
Florida Power Corporation
P. O. Box 14042
St. Petersburg, FL 33733-4042

Timothy Woodbury
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, FL 33688-2000

Matthew M. Childs, Esq. *
Steel Hector & Davis
215 South Monroe Street, Suite 601
Tallahassee, FL 32301

Linda Quick
South Florida Hospital
and Healthcare
6363 Taft Street
Hollywood, FL 33024

Kenneth Hoffman, Esq. *
Rutledge Law Firm
P. O. Box 551
Tallahassee, FL 32302

John T. Butler, Esq.
Steel, Hector & Davis, LLP
200 South Biscayne Boulevard
Suite 4000
Miami, FL 33131-2398

Lee Schmudde
Walt Disney World Co.
1375 Lake Buena Drive
Fourth Floor North
Lake Buena Vista, FL 32830

Beth Bradley
Mirant Americas Development, Inc.
1155 Perimeter Center West
Atlanta, GA 30338-5416

Suzanne Brownless, Esq.
1975 Buford Boulevard
Tallahassee, FL 32308

Jon C. Moyle, Esq.
The Perkins House
118 North Gadsden Street
Tallahassee, FL 32301

Steven H. McElhaney, Esq.
2448 Tommy's Turn
Oviedo, FL 32766

Thomas A. Cloud, Esq.
W. Christopher Browder, Esq.
Gray, Harris & Robinson, P.A.
P. O. Box 3068
Orlando, FL 32802-3068

David E. Goroff, Esq.
Peter K. Matt, Esq.
Bruder, Gentile & Marcoux, LLP
1100 New York Avenue, N.W.
Suite 510 East
Washington, DC 20005

William G. Walker
Florida Power & Light Company
215 S. Monroe Street, Suite 810
Tallahassee, FL 32301

Michael B. Wedner
Assistant General Counsel
117 W. Duvall Street, Suite 480
Jacksonville, FL 32202

P. G. Para
Director of Legislative Affairs
JEA
21 West Church Street
Jacksonville, FL 32202

William T. Miller, Esq.
Miller, Balis & O'Neil, P.C.
1140 Nineteenth Street, N.W.,
Suite 700
Washington, DC 20036-6600

Leslie J. Paugh