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May 13, 2004

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; Calpine Corporation Response to GridFlorida Applicants' Market Design Positions.*

Dear Ms. Bayó:

Enclosed for filing please find one (1) original and fifteen (15) copies of the Calpine Corporation Response to GridFlorida Applicants' Market Design Positions, submitted for filing in the above-referenced docket. Please also find the enclosed diskette, containing an electronic version of the Filing in Word format. Copies of this letter and the Calpine Corporation Response are being distributed via E-mail on this same date.

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

Enclosures: Response (original and 15 copies)
Diskette

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

| | |
|---|---|
| In re: Review of GridFlorida Regional Transmission Organization (RTO) Proposal | Docket No. 020233-EI<br>Filed: May 13, 2004 |

**Calpine Corporation Response to GridFlorida Applicants' Market Design Positions**
**Market Design Workshop May 19-21, 2004**

Based on Calpine's review of the GridFlorida Applicants' submitted comments, Calpine understands that the Applicants are continuing to propose a combination of resource adequacy and economy markets under a GridFlorida RTO. Calpine further understands that the Applicants propose that the economy energy and ancillary services be handled under an LMP-based congestion management and market settlement framework. With respect to the detail of that framework and the corresponding market monitoring and mitigation, the Applicants identify a number of alternative approaches. The Applicants do not offer the same level of detail on resource adequacy. Based on this understanding Calpine offers the following comments.

Based on experience with development of other wholesale power markets, Calpine believes that a well functioning economy market for spot energy and ancillary services first requires an effective reliability assurance and planning structure. Without such a structure, market participants may focus too heavily on energy-only, spot market prices, at the expense of more forward looking price signals that are necessary to ensure the availability of long term capacity. Real time spot markets for energy and ancillary services do not, in short, provide reliable long term price curves. This result can lead to scarcity conditions or, worse yet, concentration of market power. Assuring a sound resource adequacy framework, integrated with RTO-level system planning, can address impending shortages or market concentrations prospectively and thereby respond to market dynamics on a timeline that permits competitive solutions to be brought to bear.

**Developing a Solid Reliability Foundation**

Notwithstanding the current existence of multiple utility transmission tariffs, the interconnected Florida electrical system operates as a single synchronous machine. Tie lines between utility control areas reflect tariff boundaries and electrons flow freely albeit influenced by the use of generator-based regulation control by each utility's control area operator. The existence of these separate tariffs and control areas, however, does not change the laws of physics. Multiple control area operations simply means that administrative constraints are imposed on system operation as well as providing multiple sets of brake and accelerator (dispatch and regulation control) to the same machine. The same inefficiencies exist at the planning stage where the balance in execution of generator versus transmission construction occurs at an individual utility level (subject, of course, to the installed capacity reserve margin requirement).

In order to assure optimal system operation in a future period, it is appropriate to plan the development of infrastructure, acknowledging its need to reliably satisfy the aggregate of Florida load (not just the individual utilities' load). In fact, this plan and its execution (commitment to build transmission or buy/build generating capacity) is the foundation upon which the economy power markets will operate. Reliable and efficient operation of that future economy market is affected by the action or inaction of load serving entities and transmission companies on the planning horizon. Hence, coordination and development, by GridFlorida, of a Florida-wide generation and transmission plan, including the plan to address concentrations of supply, is fundamental to proper functioning of spot economy markets for energy and ancillary services. This forward planning is necessary both to the buyer (since it can mitigate its exposure to spot energy prices, including new entry which is possible on this time horizon), and to the seller with large supply concentration (providing a reasonable degree of certainty as to its opportunity to recover capital costs in the future period). Calpine therefore proposes that GridFlorida's first market design focus should be a strong foundation in reliability markets and reliability planning.

On a given planning horizon (lead time for new transmission and generation construction), the RTO would conduct a baseline, Florida-wide transmission and generation reliability analysis. All transmission capability purchased by Network Customers (transmission rolled into rates) and all generating capability which Network Customers own or have purchased as capacity for that period are considered in the reliability analysis. Where local or regional reliability needs are identified (the current Florida Public Service Commission threshold is understood to be 20% for jurisdictional utilities and the non-jurisdictional utilities in Florida appear to follow this threshold as well), the RTO will require the responsible Network Customers to pursue generating capability purchases (including new generation) while the RTO will identify transmission expansion alternatives, and consider subsequent roll-in of generator interconnection related network upgrades[1].

The iterative RTO planning process would assure reliability for the aggregated Florida system, and provide the framework to enforce a generating capacity requirement and balance that requirement with transmission expansion alternatives. In either case, those who require the associated capability to meet firm load needs would pay.

In order to add further meaning to the generating capacity purchase and provide market–based means of mitigating market power in the spot energy market, each generating capacity seller would agree to provide the buyer with:

[1] Presuming that GridFlorida would seek an independent entity variation for upgrade cost allocation.

**Real Power Capability:**

- Product Description – Energy call option contingent on unit availability and operation subject to performance requirements. Establishes discrete terms and conditions on the extent to which the buyer may rely on the associated capability for its load reliability planning purposes.

  - Energy Strike Price - $1000/mwh default level (state PSC or RSC could require a lower strike price for all purchases by its jurisdictional utilities). This item may be set to lower levels to address any market power mitigation concerns. This would require the state PSC to balance the desire to prevent the exercise of market power with a given utility's responsibility to achieve the greatest economies for its ratepayers[2].

  - Energy Call Availability – Buyer provides the portion (pro-rata capacity ownership for the period) of energy revenues for generation priced in the RTM above the strike price of the capacity purchase.

  - Energy Call Performance Requirement – Seller is obligated to offer its unit into the Day Ahead and Real Time markets up to the amount of capacity sold to loads in that period.

  - Energy Call Performance Measurement – Seller fully meets performance requirement if commercial unit forced outage rate less than system-wide target rate (simply average of all capacity unit commercial forced outage rates for prior 3 years).

  - Energy Call Performance Penalty – Seller must provide a financial call option equivalent for all remaining hours in the year following the hour in which the unit first exceeds the system-wide target rate and the unit remains forced out or subsequently declares a forced outage. The seller may alternatively provide a call option from an alternate unit in the same RTEP zone that was not previously sold as UCAP in that period.

- Minimum Purchase Lead Time – Load (buyer) is required to demonstrate resources sufficient to meet its portion of the GridFlorida reliability plan for year 4 (three year lead time). Aggregate of load must demonstrate RTEP sufficiency for that future year prior to June 1st, three years in advance.

- Minimum Purchase Term – 12 months (or less if buyer purchases capability from 2 separate units in each season).

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[2] If the strike price were set at the marginal operating cost of the facility, any gross margin from economy energy sales would go to the entities paying for the capacity. In the case of a vertically integrated utility, this would be its ratepayers. The amount of energy revenues above the strike price would then be passed through to its ratepayers as a fuel clause discount.

- Other Supplier Requirements –
  - Cannot deactivate/retire the unit in the period of capacity service.
  - Must coordinate maintenance outages through GridFlorida approval.
  - Must bid megawatts sold as capacity into the day ahead and real time markets.
  - Subject to bidding restrictions:
    - $1000/mwh cap
    - LOL bid as low as technical capability permits (only applies where aggregate capacity sales/self-supply exceeds that level).
    - Start-up time no greater than 24 hours.
    - Start-up/No load bid updates limited to bimonthly.

**Reactive Power Capability:**

Compensation for provision of access to reactive capability from generator facilities would continue to occur through cost-based reactive power charges pursuant to generator rate filings approved by the FERC and charged to Network Load through the RTO Tariff.

**Implementing Economy Energy and Ancillary Service Markets**

The Applicants written comments focused more heavily on the real time system operation and clearing of the economy energy and ancillary markets. Calpine responds to various aspects of those market component proposals.

**Economy Energy Market**

The economies of the spot market products (spot energy and ancillary services) require a centralized Florida wide least as-bid cost dispatch under a single automatic generation control scheme, which would not have multiple internal control areas. In order to resolve energy imbalance accounting between market participants who provide cheaper economy energy beyond their own needs and other market participants who consume more energy than they generate, some form of energy imbalance settlement will be required. While the Applicants provide numerous options ranging from pay-as-bid, with physical transmission rights and balanced schedule requirements to full nodal LMPs with marginal pricing of losses, the question boils down to what is needed on day 1 versus what market participants envision as day 2 market structures.

While many of the discussions surrounding energy imbalance markets in Florida have discussed LMP as having comparatively higher development and implementation costs and being more complex, Calpine is not convinced that such is actually the case. Calpine believes that pursuit of non-LMP approaches may indeed incur higher costs over the long term. In all cases other than the LMP approach, GridFlorida would have to initiate development of its own system and incur the development costs of such an approach. A tremendous benefit of an LMP-based system is that the development of these systems has already been completed. The software and hardware to implement this approach already exists and could be implemented in Florida at a more certain cost (no good estimate exists to develop a homegrown approach under an alternative form of pricing). That being said, some of the more sophisticated elements of LMP market design, such as marginal pricing of losses, FTRs as options versus obligations, etc., do not need to be considered on day 1.

While the calculations that underlie LMP based systems are internally sophisticated, the transparency and efficiency that such an approach provides to congestion management and economy energy transactions cannot be achieved through any other means. Moreover, the complexity that existing software systems have internalized into the LMP calculations must be addressed externally by any other system. For example, Calpine had identified numerous flaws in the Applicants' prior proposal to employ a physical rights based congestion management system with a balanced schedule requirement. If GridFlorida chose to go in an untested direction such as that initially proposed by the Applicants, many complex issues would need to be solved for the first time, and without benefit of precedents. While LMP-based computer algorithms can consider multiple cost tradeoffs in dispatch subject to transmission constraints, a physical rights system has to rely on the unwieldy and inefficient process of market participants trading coupons. Such a system may very likely mean much higher costs for resolving congestion. On the other hand, LMP-based dispatch, pricing and settlement software can do it quicker and better, and do it using software that exists today. (We note that the Applicants are no longer advocating the physical rights model, so we might be beating a dead horse.)

Even under an LMP-framework, it may be advisable for GridFlorida to stick to the basics (i.e. Nodal LMPs for generators and zonal LMPs for load). Charge all load for losses on an hourly average basis. Initially limit imbalance trades to the real time spot market and forego implementation of a day-ahead market. The latter, including hedges against future hours LMPs, could be accommodated through bilateral trades.

Consideration of Related Issues:

- <u>Clearing vs. Pay As Bid</u> – A clearing price form of settlement provides an observable price for purchases and sales. The pay as bid approach is insufficiently transparent and that confusion in the source of costs would likely lead to disputes regarding the level of payments and their allocation to Florida load. On the other hand, a clearing process allows greater transparency and would facilitate more efficient market participation, including evaluation of the cost of self-supply versus spot market purchase. This latter step may assist the

Commission in monitoring the cost effectiveness of self-supply strategies by its jurisdictional utilities.

- Centralized vs. Bilateral vs. Hybrid – A centralized real time spot energy market is needed at the outset. However, it may be possible to defer implementation of a day-ahead market and rely on bilateral trades and self-commitment of resources to provide that function.

- Integrated (financial transmission rights) vs. non-Integrated (physical transmission rights) – Calpine, in it's filing to the FPSC dated June 21, 2002, a copy of which is attached as Attachment A and incorporated herein by reference, provided numerous examples of the flaws of a physical rights approach. Those concerns remain valid today.

- Single vs. Multi-Settlement – It is possible to rely on a single settlement (real time LMP market only) with the use of bilateral transactions to provide forward purchase/sale opportunities.

- Nodal vs. Zonal – Recommended that generator spot purchases and sales occur at the nodal level. Given that load is serviced by single load serving entities within each service territory, it may be feasible to settle load spot purchases at zonal prices.

- Bid Structure – If employing only a real time LMP market, start-up and no load bid prices would not be needed. They apply only where the RTO is committing generation on-line as a normal market operation step (day ahead market). Under a single settlement, if a generator were able to change its minimum run time or minimum loading level at its choosing (restrictions may exist for units sold as capacity), such generator owners could manage their risk of being committed on line by the RTO.

- Cost-based or Market-based – All bids should be market based. Concerns about market power should be addressed through the energy call option-based capacity product purchases and related energy strike price (see above). Reliance on administratively determined caps or other intrusive forms of mitigation disrupts economic market function and distorts pricing in the most important periods – ***when energy is in short supply***.

- Day-Ahead Bidding Requirement – LSEs should be obligated to offer the capability of generation from their capacity resources and to offer the dispatch flexibility of those resources to facilitate RTO system operating flexibility and scheduling of necessary ancillary services in real time. However, portions of units not sold as capacity should not be obligated to schedule any portion of their resource in the day-ahead market (This should not present a problem as the absence of a capacity purchase should be dispositive that the resource is not "pivotal".)

- Limitation on Use of Day Ahead Market – If a Day Ahead Market is employed at the outset, no balanced schedule requirement is necessary. However, if only a real time market is implemented at the outset, then the RTO will need some form of assurance that adequate generation is committed on-line by LSEs, with sufficient dispatch flexibility to meet forecasted load requirements plus ancillary services.

- Single vs. Multiple Control Areas – Clearly, a single RTO control area provides the most efficient solution to security-constrained economic dispatch and to real time market pricing. It makes no operational or economic sense for each IOU to have its own regulation and frequency response scheme in place at a local control area level. Such multiple response schemes create excess costs and likely work at odds with the RTO's real time system operation.

- Loss Responsibility – Losses should be calculated at an average loss level. The RTO should charge Network Customers pro-rata to their hourly load for the system costs in supplying energy to satisfy system losses. While some ISOs have attempted to compute marginal losses, all such approaches involve flaws arising from the manner in which the slack bus is selected.

**Ancillary Service Markets**

Given the integrated nature of Florida's existing load serving entities, it may be less crucial to establish an explicit bid-based ancillary service market at the outset. It may be possible to require load serving entities to offer adequate ancillary service capability from their "capacity" units. This is particularly important for regulation control as that service requires a generator to have necessary communication and dispatch control equipment unique to that service. Calpine would note, however, that a Florida-wide control area operation, would provide the opportunity to decrease the quantity of automatic generation control capability necessary to maintain system frequency and tie line schedules. Currently, each Florida utility must exercise that level of control within its own control area. Under a Florida-wide dispatch (control area), inter-utility tie lines are internalized and less local control is needed. Consequently, Calpine supports the establishment and operation of a Florida-wide, competitive ancillary services market.

Respectfully submitted this 13th day of May, 2004.

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**Attachment A**
**Docket No. 020233-EI**

**(Pages 2-21 of Joint Post-Workshop Comments June 21, 2002)**

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

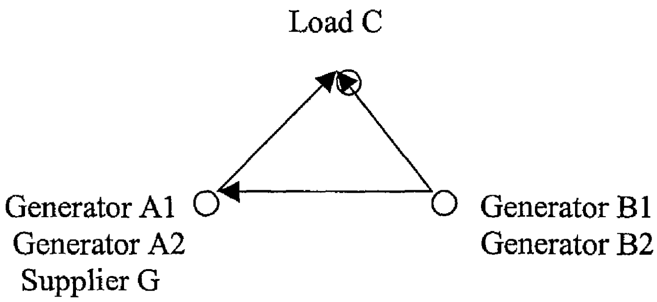
The following presents a series of numerical examples demonstrating FTRs with LMP and compares the FTR model against the PTR with balanced schedules model. In addition, the numerical examples demonstrate the manner in which market power can easily be exercised under the PTR paradigm.

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 Physical Transmission Rights (PTRs) model for addressing aggregate Florida needs. [TR 169, 3-12] Under the LMP/FTR paradigm, transactions proceed on a physical basis disciplined by the locational marginal prices without socialization but with price certainty. Reliability is served and costs rationally minimized because price transparency enables market participants to make appropriate decisions for their transactions in the appropriate time frames.

By contrast, as is demonstrated below, under PTRs, access to least-cost supply information and least-cost supply are both severely restricted and the potential for market power abuse is great. Diminished access occurs as a result of the flowgate requirement and the balanced schedule requirement. Under a balanced schedule requirement, generation without load will not be entitled to submit to the Scheduling Coordinator resulting in administrative withholding. In addition, the balanced schedule requirement does not factor in unit commitment requirements such as startup, shut down, and minimum run times resulting in a lack of access to supply options with requirements in excess of 30 minutes ahead of real time. [TR 156, 1-21] By contrast, 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.

Like balanced schedules, the flowgate congestion management system effectively restricts the utilization of least-cost supply. For example, a transaction will not flow unless the requestor holds sufficient rights over *all* impacted flowgates. A PTR holder with knowledge of the need for a full compliment of rights can withhold transmission capacity which will result in uneconomic dispatch (presumably to favor the holder's own units), decreased reliability and the potential for windfall profits - all to the detriment of the Florida's ratepayers. In short, with PTRs, knowledge of the marketplace is never gained and least-cost generation going to load is never accomplished. [TR 181, 20-23] By contrast, under the LMP/FTR model, FTR holders cannot force withholding of any generation and 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 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 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's") 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 load serving entities' generation not used to meet its 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 MW 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<br>100 x (27-22) = $500<br>200 x (27-23) = $800<br>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 FPC/FPL 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 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.

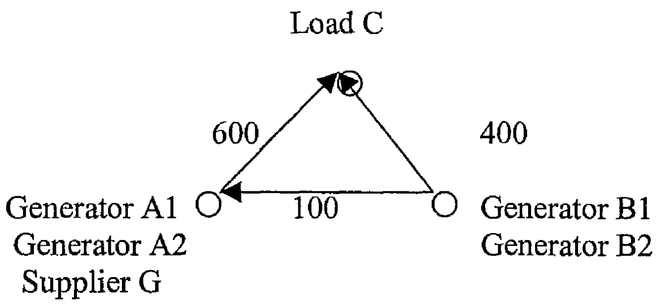
| | Morning Off-peak | Peak Hours | Evening Off-peak |
|---|---|---|---|
| Generator A1 – 26 | 100 | 200 | 100 |
| Generator A2 – 27 | 0 | 50 | 0 |
| Generator B1 – 22 | 100 | 250 | 100 |
| Generator B2 - 23 | 0 | 0 | 0 |
| Supplier G - 30 | | | |
| Total Generation | 200 | 500 | 200 |
| Total Generation 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<br>200 x (26-23) = $600<br>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 MW 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

FPL/FPC approach is access. While the FPL/FPC approach advertises "real time" imbalance dispatch, many aspects of its design will preclude IPPs 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.**




**<u>GENERAL ASSUMPTIONS:</u> (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. each hour can be scheduled and evaluated independent of all 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 simplified 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 an 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 $26.4 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<br>200 x (26-23) = $600<br><br>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 not accepting a generator-only schedule. The second is economic withholding which occurs as a result of applying an imbalance tax to net actual generation. 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 short, the proposed design does not assure reliability, encourages misstatement of load to achieve balance in submittals 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 and 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 its generators face equipment problems, it 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 simplified 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 is so because the initial absence of transparency obscures from PTR holders of FGBA and FGBC the opportunity for economic PTR sale and no redispatch solutions exist to provide non-firm PTR service. It should be noted that the absence of redispatch solutions could very well be due to withholding of decremental bids under 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<br>100 x ($27-22) = $500<br>200 x ($27-23) $800<br>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 right 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 period (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 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 so because full load 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 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 at C, $22 at B and $22 at A since there is no congestion. The FTRs holders do 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 simplified 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(i)** – Everything else simplified as in Case 1, but now also consider the impact of adding a balanced schedule requirement. Assume that Generator B2 is not owned by or purchased by an SC with load thus it cannot submit a balanced schedule but Generator B1 is purchased by an 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. 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 simplified 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)** – 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 so 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<br>100 x ($27-22) = $500<br>200 x ($27-23) $800<br>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 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 periods PTR than Load C's increased cost for such period (PTR charge $799 + $2099 + $799)) As in earlier case, 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 FTR/LMP 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 at C, $22 at B and $22 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 rest of 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 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 FTR/LMP model is superior to that proposed by the GridFlorida Applicants in several important ways; cost and functional efficiency and responsible cost allocation. By contrast, PTRs are inherently inefficient and expensive and provide 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, 7-9]. 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 from such access. The incumbents will assume real-time energy market control, run the regulation ancillary service market and profit from socialization of pricing which remaining undetected due to the lack of transparency. [TR 1564, 11-17]. 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