ORIGINAL

RUTLEDGE, ECENIA, PURNELL & HOFFMAN

PROFESSIONAL ASSOCIATION
ATTORNEYS AND COUNSELORS AT LAW

STEPHEN A ECENIA
RICHARD M ELLIS
KENNETH A HOFFMAN
THOMAS W. KONRAD
MICHAEL G MAIDA
MARTIN P McDONNELL
J. STEPHEN MENTON

POST OFFICE BOX 551, 32302-0551
215 SOUTH MONROE STREET, SUITE 420
TALLAHASSEE, FLORIDA 32301-1841

TELEPHONE (850) 681-6788
TELECOPIER (850) 681-6515

R. DAVID PRESCOTT
HAROLD F X PURNELL
MARSHA E. RULE
GARY R RUTLEDGE

GOVERNMENTAL CONSULTANTS
MARGARET A MENDUNI
M. LANE STEPHENS

April 29, 2004

Ms. Blanca S. Bayo, Director
Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Betty Easley Conference Center, Room 110
Tallahassee, Florida 32399-0850

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Re: Docket No. 020233-EI

Dear Ms. Bayo:

Enclosed for filing in the above-referenced docket are the original and fifteen copies of the GridFlorida Applicants' Issues for the May 19-21, 2004 Market Design Workshop. Copies of the GridFlorida Applicants' Issues were distributed today to all stakeholders on the GridFlorida E-mail Exploder List.

Please acknowledge receipt of these documents by stamping the extra copy of this letter filed and returning the copy to me.

Thank you for your assistance with this filing.

Sincerely,

Kenneth A. Hoffman

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Issues for May 19-21, 2004 Market Design Workshop
Docket No. 020233-EI

This document, and the matrix attached hereto, includes (a) a brief overview of the history of the GridFlorida market design, (b) a discussion of some of the issues associated with developing a market design structure for GridFlorida, (c) the Applicants' proposal for discussing these issues, as well as any other market design issues raised by stakeholders, at the upcoming market design workshop, and (d) an update on the status of the cost-benefit study to be prepared by ICF Consulting ("ICF"). These documents discuss five of the six issues Commission Staff identified in its April 6, 2004 Memorandum addressing the market design issues workshop. The Applicants will be prepared at that workshop to discuss the sixth issue, *i.e.*, any changes since the pricing issues workshop to the current regulatory/legislative environment as it relates to the development of GridFlorida.

History of GridFlorida Market Design

On March 20, 2002, in conformance with the Commission's Order No. PSC-01-2489-FOF-EI (December 20, 2001), the Applicants filed a Revised GridFlorida Proposal for the Commission's review. That filing proposed, among other things, to continue the market design structure that earlier had been filed with the FERC and reviewed by the Commission. Under that market design structure, GridFlorida would manage congestion through a flowgate approach with physical transmission rights ("PTRs"). Each scheduling coordinator would submit balanced schedules of generation and load, including necessary PTRs, to the Regional Transmission Organization ("RTO") on a day-ahead basis. GridFlorida would rely on mandatory incremental bids ("incs") and decremental bids ("decs") submitted for generators to manage real-time congestion, and generators would be paid what they bid in the inc/dec market, rather than a market clearing price. Load or load serving entity ("LSE") pricing would be calculated on a zonal basis, rather than determining a price at each node on the system.

On September 19, 2002, the Applicants filed a "Petition of the GridFlorida Companies Regarding Prudence of GridFlorida Market Design." That Petition set forth a new market design structure based on congestion management and energy markets that would utilize financial transmission rights (as opposed to physical transmission rights) and locational marginal pricing (as opposed to zonal pricing). The market design included in the September 19 Petition often is referred to as an "LMP" model. That market design would include a voluntary day-ahead market and a real-time market, mechanisms to protect against undue reliance on the real-time market, and payments of market clearing prices calculated on a "nodal" basis. A balanced schedule requirement was not proposed as part of that filing.

Both proposals would include mechanisms to ensure resource adequacy, an allocation of transmission rights to existing users to protect those users, to the extent possible, for congestion costs, an annual re-allocation of transmission rights for new resources and to reflect native load growth, market power mitigation measures to provide safeguards against abuses of market power, and a hierarchical control system, wherein existing control areas may be maintained, but GridFlorida would be responsible for the short-term reliability and overall performance of the system.

Identification of Issues Associated with Market Design Structures

The matrix attached hereto provides an overview of some of the issues associated with various alternatives to market design structures under an RTO proposal. Among the fundamental issues that must be decided on a final basis are how energy is to be priced, how any centralized markets will be monitored and the market mitigation rules that will apply to such markets, the treatment of existing control areas, and the treatment of ancillary services.

In identifying the issues included in the matrix, the Applicants considered prior stakeholder discussions regarding GridFlorida market design, as well as existing and proposed markets for Independent System Operators ("ISO") or RTOs throughout the country. A brief overview of those markets follows:

- In the New York market, a single system operator (the New York Independent System Operator or "NYISO") operates complex energy, capacity, and ancillary services markets based on an LMP model, including marginal pricing of real power losses and co-optimization of energy and ancillary services markets. Unlike most other established ISOs and RTOs, the New York market consists of a single state. New York's vertically integrated transmission owners were required by their state commission to divest most of their in-state generation resources. Consequently, most power used to serve load is purchased bilaterally, with residual purchases made through the NYISO administered markets. Also, New York has state commission-mandated retail access programs. Prior to the NYISO, transmission system operations in New York were, for several decades, coordinated through a tight power pool ("NYPP"). Many of the NYPP employees became NYISO employees at the commencement of NYISO operations in 1999.

- The New England states rely on the New England ISO ("ISO-NE") to coordinate the transmission system in multiple states (including Massachusetts, Maine, Rhode Island, Vermont, New Hampshire, and Connecticut). Like New York and PJM Interconnection L.L.C.("PJM"), New England relied on a tight power pool for decades before converting to an ISO structure. As of March 2003, New England uses an LMP-based system (with marginal losses) to dispatch resources and price congestion. Many of the utilities in New England have sold significant amounts of generation resources to companies engaged in marketing activities, sometimes on a voluntarily basis or, as in Maine, at the direction of the state commission. Some New England states have implemented retail access programs.

- PJM, an operator responsible for dispatching resources in multiple states, including Pennsylvania, New Jersey, Delaware, and Maryland, has characteristics in common with New England and New York. Like ISO-NE (and unlike NYISO), PJM operates over multiple states. Although PJM uses LMP to price energy and congestion, unlike New York and New England, PJM prices real power losses using a system average methodology rather than marginal losses. However, PJM currently is moving toward implementation of a marginal loss method. Unlike utilities in New York, many of the utilities in PJM have retained ownership of significant generation assets. Like New York and New England, PJM had its genesis in a tight power pool that first formed in 1927 (with three utilities, additional utilities joined in 1956, 1965, and 1981). Some states in PJM have implemented retail access programs.

- The Applicants also considered proposed markets in the Midwest ISO, the Southwest Power Pool RTO proposal, and the SeTrans RTO proposal. The Midwest ISO recently filed its LMP-based energy markets proposal and has proposed an effective date of December 1, 2004. At the time of the filing, many issues remained unresolved, including allocation of financial transmission rights and revenue sufficiency, a comprehensive resource adequacy proposal, and control area coordination. Unlike PJM, NYISO, and ISO-NE, Midwest ISO proposes to coordinate rather than consolidate its 35 different control areas. The Southwest Power Pool has not selected a specific market design but has taken significant steps in developing governance criteria and establishing a schedule that allows for the systematic phase-in of the markets to be developed. Finally, while development of SeTrans was suspended on December 11, 2003, significant progress had been made on Day 1 and Day 2 market design structures. Day 2 market design was being discussed as an LMP-based structure.

- The California Independent System Operator ("Cal-ISO") operates the transmission system and energy markets in most of California. Unlike the majority of markets in the U.S., the Cal-ISO markets were established using a zonal scheme rather than LMP. Cal-ISO is currently converting to LMP. The impetus for establishment of the ISO was to allow retail direct access (which subsequently was suspended), and the enabling legislation included a requirement that all utilities divest a minimum of 50 percent of their owned generation. The Cal-ISO initially operated only the real time market, with a separate entity (the California Power Exchange, "Cal-PX") operating the day-ahead market. Cal-ISO now operates both, due to the bankruptcy of the Cal-PX.

- The Electric Reliability Council of Texas ("ERCOT") is a non-FERC jurisdictional ISO established to allow retail access in most of Texas. Like Cal-ISO, ERCOT was established using a zonal scheme. Transmission constraints between zones were "uplifted" to load. Due to the size of the congestion payments, the Public Utility Commission of Texas has ordered ERCOT to convert to an LMP energy market. ERCOT does not have a day ahead market for energy; the scheduling entities must submit balanced schedules of supply and load. Day ahead markets, however, are in place for ancillary services. A day-ahead energy market will be included within the new LMP market design.

Workshop Discussions

The Applicants will present the various options and issues briefed in this document and the attached matrix at the workshop. The questions identified in the matrix, and many other questions, must be answered with enough detail to assess the impacts on retail customers, utilities, and other LSEs.

Although there are many similarities between the regions discussed above, and their markets, significant regional differences required many individual variations in market design. Like these other regions, the Applicants do not believe that a single existing (off-the-shelf) proposal would address the characteristics unique to Peninsular Florida. These unique characteristics include:

- Peninsular Florida comprises most, but not all, of the State of Florida, and is similar in scope to ERCOT and the California ISO.

- Florida is a peninsula and is interconnected to the rest of the country only at the Georgia transmission system. Energy import and export opportunities to and from Florida are limited significantly.

- The FPSC has not required the Applicants to divest their generation resources and, therefore, the Applicants have sufficient owner-controlled capacity to serve their native load. As a consequence of retaining sufficient generation to serve load, the Applicants may be considered to have market power in generation and may be subject to mitigation.

- The Florida Legislature has not enacted retail access legislation, nor have the Applicants implemented a retail access program.

- Florida has a robust FPSC-jurisdictional demand-side management program.

- The FPSC has approved an installed capacity reserve requirement that applies to load of investor owned utilities in Peninsular Florida.

To provide the greatest benefits reasonably possible for retail customers in Florida, and in light of the unique characteristics of Peninsular Florida, the Applicants believe that certain core objectives for an energy market for Peninsular Florida must be satisfied:

- The market design should ensure the economic, safe, and reliable delivery of power to customers in Peninsular Florida.

- The market design should provide net benefits to customers while minimizing their costs and risks.

- There should be assurance of sufficient resources (*e.g.*, installed capacity reserves) to provide adequate and reliable service to the customers of Peninsular Florida.

- The market design should include monitoring and mitigation procedures to prevent the exercise of market power.

The Applicants believe that the discussions at the workshop should be conducted with the goal of satisfying these core objectives under any market design proposal ultimately adopted for Peninsular Florida.

The Applicants have attempted to identify the major issues and options associated with developing a market design structure for the unique GridFlorida footprint. However, given the complexity of these issues, their inter-related nature, and the many details and impacts that still need to be evaluated, the Applicants are not yet in a position to express conclusions on these issues. The Applicants encourage interested stakeholders to prepare and circulate written presentations addressing the options outlined in the Applicants' issues matrix and to be prepared to present their views at the market design workshop. Such stakeholder input will facilitate the Applicants' ongoing analysis of the market design issues.

Update on the ICF Study

The ICF cost-benefit study will assess the costs and benefits of establishing GridFlorida, including changing the current bilateral market structure in Peninsular Florida to a market structure that is consistent with the Applicants' September 19 Petition. ICF currently is preparing a project description and an assumptions book that will apply to its analysis. The Applicants expect that these documents will be distributed to interested stakeholders in advance of the market design workshop.

ISSUE 1 MARKET DESIGN AND CONGESTION MANAGEMENT			
Market Design Issues	**Sub-Issues/Options**	**Description**	**Comments**
How to Price Energy	Pay as Bid or Market Clearing Price Under Centralized Market, Bilateral Contracts, Hybrid	Pay as bid - generators committed and dispatched to serve load would be paid the price they submitted as a bid, not a market clearing price. Market clearing price - generators that are committed and dispatched in merit order are paid the same energy price absent congestion. Bilateral contracts - prices developed through bilateral contracts with no centralized market. Hybrid - combination of bilateral markets and centralized markets.	Market clearing prices provide an incentive for suppliers to develop more efficient processes to reduce costs and maximize profits. Market clearing prices allow bids at short-run marginal costs. Significant market power issues can arise under market clearing price structure. No US markets currently use pay-as-bid. Bilateral contracts are used in today's market in Florida, and are the basis for Entergy's recently filed "Weekly Procurement Process" ("WPP") proposal at FERC (which includes formalized procurement rules but relies on bilateral contracting). GridFlorida physical rights proposal was a hybrid model; bilateral contracts prior to real-time operations, central market to address real-time imbalances and real-time congestion.

Market Design Issues	Sub-Issues/Options	Description	Comments
	Transmission Service - Integrated or Not-Integrated With Energy Supply	When transmission is integrated with energy supply, a seller in the markets is not required to obtain separate transmission service, it only needs to submit bids in the markets to sell power. Generally, the embedded cost of the transmission grid is allocated to load, and congestion costs are allocated to bilateral transactions and transactions in a centralized market based on energy prices in that market. When transmission is not integrated with energy supply, either the seller or the purchaser must obtain a separate physical right to use the transmission system in order to make a sale of power.	An integrated approach is the approach under an LMP model with financial transmission rights. A non-integrated approach is used today for transactions in Florida, and was used with the Florida broker. Energy markets and the right to transmission are completely separate. The GridFlorida physical rights model was a combination: non-integrated prior to real-time (there was no day-ahead market) and integrated for purposes of delivering imbalance energy.
Issues Under A Central Market Approach	Market Settlements	A single settlement system includes only one market, typically a real-time (hourly) market. A two settlement system includes both a day-ahead market and a real time-market, the latter of which typically addresses real-time imbalances and real-time congestion.	For some time, California was a single settlement system due to the bankruptcy of the Cal-PX, which ran the day-ahead market. A two settlement system is used in all US RTO's currently operating markets. However, in ERCOT the current day-ahead market is limited to ancillary services; a day-ahead market for energy currently is being designed.

Market Design Issues	Sub-Issues/Options	Description	Comments
	Nodal or Zonal Pricing	Nodal - prices can be calculated specific to each load bus and generator bus (thousands of prices). Zonal - prices can be calculated after load and generations is aggregated into zones based on existing service territories, congestion profiles or some other method.	In deciding between zonal and nodal pricing, customers should weigh simplified market design and administration (significantly fewer prices) against reduced price signals. Most existing zonal markets are converting or have converted to nodal markets. Unclear whether nodal pricing and pay-as-bid pricing can be combined.
	Bid Structure	Single part bids - each bid consists of one bid price ($/MWh). Multiple bids - each bid can include multiple cost components (*e.g.*, energy, no load, start-up). What costs should be included in bids? (i)Variable costs. (ii)Variable and fixed costs.	Single part bids can add complexity to developing efficient bidding strategies, and thus can lead to inefficiencies. Multi-part bids can make it easier to police bidding behavior. The costs that should be included in bids will depend on the energy pricing approach and the bidding rules.

Market Design Issues	Sub-Issues/Options	Description	Comments
	Cost Based or Market Based Bids	Cost based bids - bids based on the actual cost to supply energy and capacity. Bids could include variable costs (*e.g.*, variable O&M, fuel) and fixed costs (*e.g.*, capital costs). Market based bids - bids based on competitive market pricing subject to applicable mitigation measures to prevent the exercise of market power.	Cost based bids can help alleviate market power concerns under a pay-as-bid structure. Market-based bids provide an incentive to reduce costs to create competitive savings.
	Day-Ahead Bidding Requirement	Voluntary bids - no one is <u>required</u> to bid. Partial mandatory bids - LSEs have an obligation to bring their resources to the market in conjunction with a resource adequacy requirement (such as a requirement to have a minimum amount of available generating capacity on a daily basis). Full mandatory bids - as a condition of participating in the market, all participants must bid all of their available generation in the markets.	A number of factors must be considered when determining bidding requirements, including reliability, market power concerns, and equity. All RTO/ISO-run markets have some type of mandatory bidding or scheduling requirements, either through capacity obligations or balanced schedule requirements.
	Limitation on Use of Real-Time Market	Could have a balanced schedule requirement as part of a day-ahead scheduling process. An LSE would have to have sufficient resources available to serve its expected load (either when scheduling occurs or coming out of the day-ahead market).	A balanced schedule requirement limits use of the real-time market. A decision would have to be made on whether penalties should be established for market participants that do not satisfy the balanced schedule requirement when the imbalances are outside of specified thresholds.
Transmission	Financial	FTRs are financial rights, meaning no physical right to the	FTRs are used in PJM, ISO-

Market Design Issues	Sub-Issues/Options	Description	Comments
Congestion Options	Transmission Rights ("FTRs")	transmission system is necessary to schedule energy. Priority of use of the system is not linked to whether or not a transmission customer holds such a right. An FTR provides the holder with a financial hedge against potential congestion charges between sources and sinks on the transmission system.	NE, NYISO, ERCOT, and proposed for use in MISO and later phases of SPP. Many issues arise when developing an FTR model for transmission congestion, including: (a) FTRs must be simultaneously feasible for revenue adequacy. (b) Should transmission customers receive auction revenue rights ("ARRs") (*i.e.*, receive the revenues from FTR auctions) or FTRs? (c) How are FTRs or ARRs allocated to existing uses of the transmission system, including existing transmission agreements? (d) Should FTRs be options or obligations (*i.e.*, should the holder of an FTR be liable for congestion payments in certain circumstances)? (e) How should residual FTRs be allocated? (f) How should revenues from FTR auctions be distributed?
	Physical Transmission Rights ("PTRs")	Must have a physical right to the transmission grid to schedule energy flows.	GridFlorida's March 19, 2002 filing included an example of a physical transmission rights

Market Design Issues	Sub-Issues/Options	Description	Comments
		Congestion is managed using redispatch, or when redispatch will not resolve a constraint through transmission loading relief procedures. If no transmission capacity is available to grant a new transmission request, redispatch can be offered to grant the new service (subject to that customer paying the costs of redispatch).	model with redispatch service. Issues with PTRs include: (a) How to define facilities with commercially significant congestion and allocate rights to those facilities. (b) Determining existing customers' rights to PTRs. (c) Allocation of redispatch costs to maintain previously-approved transmission service.
	Redispatch Service	Product offered to transmission customers willing to pay the cost of redispatch to create the counter flows needed to allow a transaction to continue or to grant a new transmission service request.	Such an approach can be used under the current transmission tariff structure. A form of redispatch is currently proposed for the Entergy area in conjunction with its WPP proposal.
Control Area Options	Single Control Area	An RTO would operate as a single control area and perform all NERC control area functions.	PJM, ISO-NE, NYISO, Cal-ISO.
	Independent Multiple Control Areas	An independent entity would operate a bilateral market (possibly including redispatch service) with existing control areas maintaining their NERC control area responsibilities.	Florida Broker. Similar to Entergy WPP proposal.
	Hierarchical Multiple Control Areas	Existing control areas have option to turn-over control functions to RTO or to maintain their status as control area operator. RTO responsible for short-term reliability. Control areas responsible for regulation and frequency response functions.	GridFlorida as filed. MISO.

Market Design Issues	Sub-Issues/Options	Description	Comments
Ancillary Services	How Provided	Could establish markets for ancillary services. Could establish contractual arrangements for the RTO to obtain ancillary services from each control area operator on a cost-based basis, to allow the RTO to make the services available under the RTO transmission tariff. Parties still could enter into bilateral arrangements for certain ancillary services (*e.g.*, operating reserves), including with the control area operators. A party can self-provide certain ancillary services (*e.g.*, operating reserves).	
	Types of Services Offered	Reactive Supply and Voltage Control Service. Control of transmission voltage through adjustments to generator reactive output.	Provided by generators at no cost (per the terms of their interconnection agreement or other contract) or could be paid for at a cost-based or market-based price. Could include payment for lost opportunity cost (*i.e.*, payment for reduced energy output).
		Regulation and Frequency Response Service. Capability of a generator to increase/decrease its output in response to a regulating control signal.	Regulating capacity could be provided by generators at no cost (per the terms of their interconnection agreement or other contract), or could be paid for at a cost-based or market-based price. Net energy could be priced in a manner consistent with other

Market Design Issues	Sub-Issues/Options	Description	Comments
			energy bought/sold in the energy market. Under hierarchical structure, individual control areas are responsible for dispatching Regulation Service within their control areas. An RTO could be involved in determining regulation needs. Bid-based markets for regulation are in place today.
		Energy Imbalance Service. Energy provided to match deviations in schedules and actual load.	Prices could be cost-based or established through the real-time energy market.
		Operating Reserves Service. The amount of reserve capability required to restore tie-lines following a contingency. Spinning (*i.e.*, synchronized to the system) and non-spinning (*i.e.*, not synchronized to the system); 10-minute, and 30-minute increments.	An RTO or FRCC could establish minimum operating reserve requirements and, if applicable, allocate to the control areas. Prices could be cost-based or established through markets. An RTO could establish deliverability requirements for eligible resources.
		System Restoration Service. Ability of a generator to start-up without the benefit of an off-site power source and go from a shutdown condition to an operating condition.	An RTO or the FRCC could determine amount and locations of capability required, and certify generators as eligible to provide this

Market Design Issues	Sub-Issues/Options	Description	Comments
			service. Transmission Customers could be allocated a *pro rata* share of the payments made to system restoration service suppliers or the costs could be allocated in another equitable manner.
Losses	How Losses Will be Provided	Centrally (RTO) - losses are provided by the RTO and allocated to loads by load ratio share and to through and out transactions. Locally (control area operator) - control areas are responsible for providing the losses in their areas. Self-Supply (Generator or Load) - transmission customers are responsible for supplying their losses. Combination - above methods could be combined.	
	Calculating Losses	Average - losses are calculated and allocated using an average loss methodology (*e.g.*, average losses generated as a percentage of load served over one year). Marginal - losses are calculated on a marginal basis, *i.e.*, based on the next MW generated.	Use of marginal losses would raise the following issue: (a) Because losses are calculated on a marginal basis, excess revenues will be collected. How are those excess revenues returned to the parties that paid for the losses? (b) A reference bus to calculate marginal losses must be determined, or a distributed reference methodology must be developed to calculate marginal losses.

Market Design Issues	Sub-Issues/Options	Description	Comments
	Pricing Losses	Marginal or Average Losses - prices can be calculated as a component of LMP or priced separately. Return-in-Kind - can require or permit transmission customers to return losses in kind.	

ISSUE 2
MARKET MONITORING AND MARKET POWER MITIGATION

Monitoring Issues	Sub-Issues/Options	Description	Comments
Market Monitoring Unit "MMU"	Structure of Market Monitor	Independent board - permanently established MMU with separate Board outside of RTO. RTO staff - RTO staff performs all monitoring functions, reports directly to RTO Board (not officers). Separate contractor - hired by and reports directly to RTO Board. RTO staff with outside advisor - RTO staff performs all monitoring functions, advised by separate contractor hired to provide technical expertise, and staff reports directly to RTO Board (not officers). FPSC - performs all monitoring functions with staff or contracted employees; RTO Board has no authority to direct actions.	GridFlorida as filed includes an independent board. Use of RTO staff can cause issues regarding perceptions of independence when the RTO is running markets. ISO-NE uses a separate contractor. NYISO uses RTO staff with outside advisor.
	Funding and Budget	Submitted budget - MMU (other than contractor option or FPSC option) would submit an annual budget to RTO Board for review/approval. MMU obliged to stay within budget parameters. Contract price (Contractor option) - RFP process, contractor selected, payments subject to contract price and provisions. Actual costs - any annual budgets are projections only. Actual costs are recovered through RTO grid management charge.	
	Functions	Monitors all RTO markets. Monitors compliance with the RTO transmission tariff. Monitors RTO operations. Provides reports and information to FERC/FPSC.	The ability of the MMU to impose sanctions or penalties would be dependent on including specific provisions in the filed market monitoring documents.
Methods of Monitoring		Screen and impact test - PJM, NYISO, and ISO-NE all use screens and impact tests to initially identify potential market abuse. The screens are	

Monitoring Issues	Sub-Issues/Options	Description	Comments
		objective assessments of changes in bidding practices, quantities, schedules, or prices that are above specified threshold levels. Questionable bids identified by the screens are then subject to the impact test. If the bids did not change market prices, there is no "impact," and no need to mitigate the bids. Other - all RTO's reserve the right to investigate any activity that they believe represents market manipulation by a market participant. They use a staff of economists, statisticians, consultants, and other professionals to monitor participant behavior and identify questionable activities, which, once identified, may be subject to mitigation or reporting.	
Mitigation	Timing of Mitigation	Prior to posting and accepting a schedule - a market participant's actions could be mitigated prior to accepting and posting schedules. After posting and accepting a schedule - a market participant's actions could be mitigated after accepting and posting schedules.	If a market participant's actions are mitigated prior to accepting the schedule, the financial impact of the mitigation on the market prices are incorporated in the schedules, and reflected in the dispatch instructions. Mitigation of the actions prior to posting a schedule may delay the posting of the schedule and impact other time-sensitive functions of the RTO. ISO-NE mitigates bids before posting. If a market participant's actions are mitigated after accepting the schedule, the

Monitoring Issues	Sub-Issues/Options	Description	Comments
			financial impact of the mitigation is not reflected in the schedules or the dispatch.
	Automatic or Manual Mitigation	Automatic - all bids that fail the screen and impact tests are mitigated immediately. Market participants may challenge the mitigation to restore bids prior to final settlement. Manual - normally incorporates the screen and impact test. But market participant has opportunity to explain apparently anomalous bidding behavior. If explanation is unsatisfactory, the bid is mitigated.	Automatic mitigation is implemented in the NYISO. Manual mitigation is used by ISO-NE.
	Mitigation Measures	Reference Price - bids may be mitigated to a reference price, typically established by past successful bids, marginal costs, or a previously negotiated reference. Reliability Must Run ("RMR") Contracts - typically used to financially support units that are needed for reliability but are not economically dispatched. However, units that can exercise local market power may be given an RMR contract to establish their bidding within defined parameters. Safety-Net Bid Cap - at present, all RTO's have a bid cap in place as a safety net. In almost all markets the current cap is $1,000/MWh. A bid above the bid cap will automatically be mitigated. Withholding Sanctions - withholding can be financial or physical. Financial withholding is conducted by bidding a unit into the market at a price where it will not economically dispatch. Physical withholding is not bidding in a unit or making the unit unavailable through full or partial outage.	Financial withholding is mitigated by mitigating the bids. Physical withholding can be mitigated by requiring certain units to be bid. ISO-NE also has a unit-specific safe harbor bidding provision for peaking units in certain specified congested areas. It calculates a reference price based on generic costs for peakers and a multiplier and does not mitigate if the unit's bid price is below this safe harbor bid. The role of the FPSC must be determined.

ISSUE 3 RESOURCE ADEQUACY			
Resource Adequacy Issues	**Sub-Issues/Options**	**Description**	**Comments**
Authority to Establish the Requirement		FPSC - authority established by Grid Bill. RTO - authority delegated by FPSC (agent). FERC - has said it will defer to the states. FRCC - authority delegated by NERC or FPSC.	
Level of Resource Adequacy Requirement		Reserve Margin ("RM") = (capacity rights – weather-normalized firm peak load + firm sales)/(weather normalized firm peak load). Loss of Load Probability ("LOLP") - probability of not meeting firm load obligations due to capacity shortfalls, *i.e.*, standard of 1 day in 10 years.	ERCOT RM - 12.5 percent. MISO RM - default to state requirement or 12 percent. NYISO RM - 18 percent. ERCOT/NYISO /PJM/ISO-NE all use 1 in 10 LOLP. Highly congested areas like NYC and Long Island have local resource adequacy requirements tied to energy deliverability. ISO-NE also is moving toward this type of locational requirement.
Availability of Markets or Deficiency Auction		Centralized capacity market - a voluntary daily, monthly, and/or yearly market administered by an RTO or other entity to clear bids offered for capacity. Deficiency auction - RTO administered, mandatory periodic auction requiring deficient LSEs to purchase sufficient capacity.	PJM and NYISO have centralized markets. NYISO has deficiency auctions.

Resource Adequacy Issues	Sub-Issues/Options	Description	Comments
Term of Obligation		Short-term - daily, monthly, seasonal. Long-term - 1 (rolling 12 months), 5, or 10 years.	
Who Must Comply		The RTO, with a subsequent allocation of costs to each LSE. Each LSE in Peninsular Florida.	LSE includes all IOUs, electric cooperatives, municipalities, and municipal agencies (as well as their agents). Must determine how non-RTO members will be allocated a resource adequacy requirement.
Enforcement		Sanctions - to be applied after-the-fact and assigned by the RTO, FPSC, or FRCC. Peer Pressure - deficiency reported to FERC, FPSC, or FRCC.	

ISSUE 4 TREATMENT OF CAPACITY MARGIN[1]			
CBM Issues	**Sub-Issues/Options**	**Description**	**Comments**
Application in Peninsular Florida		No CBM - no entity, including the RTO, would be allowed to reserve CBM. All capacity resources necessary to maintain reliability would have to be contained within the RTO. Peninsular Florida/Georgia Interface - CBM allowed in ATC calculation only for the interface. Allows access to resources outside Peninsular Florida in an emergency. All control areas - all control areas would have access to resources located in other control areas.	Reserving CBM at the Peninsular Florida/Georgia Interface would be similar to the practice in PJM.
Who Establishes CBM?		FPSC - the FPSC could establish/certify CBM reservations as part of its assessment of LSE resource adequacy. RTO would include CBM amounts in ATC calculation. RTO - the RTO could designate CBM for reliability or as part of an RTO resource adequacy requirement (*e.g.*, the approach used by PJM). LSE - an LSE that is a transmission provider could designate CBM to help meet its resource adequacy criteria. The RTO would include CBM reservations in ATC calculations (*e.g.*, the approach used by some control areas outside peninsular Florida). Combination - some combination of the above.	
Associated Transmission		Physical - reservation of CBM included in ATC calculation and would constitute a physical reservation.	

1 Capacity Benefit Margin ("CBM") is defined by NERC and the FRCC. The purpose of CBM is to allow an entity to maintain reliability with a lower amount of installed capacity than would otherwise be required. CBM takes advantage of the random nature of generator forced outages and of load diversity to access generation capacity from unspecified sources on an as-needed basis. To secure access to this generation capacity, an amount of transmission capacity is reserved during the calculation of ATC.

CBM Issues	Sub-Issues/Options	Description	Comments
Rights		Financial - reservation of CBM might or might not convey an allocation of FTRs.	