ATTACHMENT 1

Commission Staff's Resource Adequacy Strawman

Preamble

Subsection (a) ***General***. Staff has no comments.

Subsection (b) ***Statement of opportunities (SOO)*.**
Subsection (c) ***Projected assessment of system adequacy (PASA)*.**
Subection (d) ***Filing of resource and transmission availability information with ERCOT*.**

Because an energy-only resource adequacy mechanism has a less-restrictive system-wide offer cap, market participants need to have more transparency on resource and transmission availability as well as market conditions that might impact prices in ERCOT spot markets. The underlying purpose of these sections is to provide market participants with an organized and systematic preview of current and future ERCOT system and market conditions.

Staff reviewed how this information was presented in Australian electric market and adopted some of the same names of the documents for use in ERCOT. Staff anticipates that ERCOT would review the information provided in the Australian SOO and PASA and develop a comparable approach. Staff also anticipates some differences in the contents of an ERCOT SOO or PASA because of the structural and topological differences between the Australian market and the ERCOT markets. ERCOT currently is gathering and publishing some of this information, so the SOO and the PASA may be thought as a way to more systematically gather and share some of that information with market participants.

Subsection (e) ***Publication of resource and demand inputs to ERCOT markets***.
In a capacity-and-energy resource adequacy mechanism, such as LICAP, a generation resource receives a capacity payment on the condition of a must-offer requirement and mitigated offer curves that are close to the units estimated short-run marginal cost (SRMC). Transparency of offer curves in such a situation may not be as critical because of the heavy mitigation involved.

Staff believes that in an energy-only resource adequacy mechanism allowing for much higher system-wide offer caps, that the transparency of offers and bids of individual market participants is critical for market participants to help the Commission police the market. The Australian market publishes offer curve information a day after a market closes. Staff believes that reducing the time between market closure and disclosure of offer and bid information will allow market participants to assist the market monitor in confronting improper market behavior or addressing the unanticipated consequences of the market design.

However, Staff has reason to believe that there is a risk of tacit collusion among resource owners to raise prices if this resource-specific information is published too soon after the market closes. The prevailing theory in the economic literature in industrial organization recognizes that the possibility of cheating on collusive price fixing is essential to the destabilization of collusive behavior:

> Following Stigler (1964), as developed by Green and Porter (1984), economists have focused on the importance of the observability of cheating to collusive stability. When cheating cannot be observed, it is harder to give firms an incentive not to cheat. It is more likely that collusion will be disrupted by cheating or by events that are empirically indistinguishable from cheating.[1]

In the same way that timely information about output from individual members of a cartel can help enforce restricted output and higher prices within that cartel, frequent disclosure of recent offer curves could enable ERCOT market participants to adjust their offer curves in a way that promote tacit collusion. This same information could allow market participants involved in this tacit collusion to observe and subsequently punish deviations from a collusive equilibrium.

While the Australian market has not experienced a problem with tacit collusion, Staff believes that certain features of Australian regulatory oversight that can't be replicated in ERCOT might be preventing such tacit collusion. Staff has offered a question for stakeholders on the timing of publishing aggregated and disaggregated inputs to ERCOT-run ancillary service capacity and energy markets.

Subsection (f) ***Approval of planned transmission and generation outages***. The purpose of this section is to recognize that if the system-wide offer cap rises under an energy-only resource adequacy mechanism, then the impact of transmission and generation outages on spot market prices could be significantly larger. As such, ERCOT needs to develop a system that considers the impacts of planned transmission and generation outages on market participants while maintaining system reliability.

Subsection (g) ***Credit standards for load-serving entities*****.** Staff has no comments.

Subsection (h) ***Improving price responsiveness of load***. Increasing the responsiveness of demand is a goal of this rule and critical to the success of an energy-only resource adequacy mechanism. This subsection proposes a mechanism that will keep the Commission informed on the review and implementation of cost-effective changes at ERCOT that would improve the price responsiveness of load. Staff notes that some related issues may be raised in Project No. 31418, *Advanced Metering Rulemaking*.

Subsection (i) ***Scarcity pricing mechanism (SPM)*****.**

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[1] Stigler G. (1964) "A Theory of Oligopoly", JPE Vol. 72, pp. 44-61; and Green, E. J. and R. H. Porter (1984), "Non-Cooperative Collusion under Imperfect Price Information", *Econometrica*, Vol. 52, No. 1, pp. 87-100.

Level of the system-wide offer cap. Staff believes that the Australian offer cap of $A 10,000 ($US 7,500) and the weekly cap on earnings (the Cumulative Price Threshold) seemed geared to addressing the Australian market's load duration curve. The attached documents show that in key parts of the Australian market, the level of peak load compared to the 98 percentile of load is much higher in South Australia (SA) and Victoria (VIC) than in ERCOT. Staff believes that differing weather patterns may account for the difference in load duration curves. ERCOT has higher average summer temperatures than in SA and VIC, but SA and VIC have summer peak temperatures significantly higher than their summer average temperatures and even ERCOT peak summer peak temperatures. Also, summers are longer in ERCOT than in the parts of temperate Australia served by the Australian electricity market.

Given that ERCOT has a longer summers with high temperatures, peaking generation resources have more hours to recover their fixed costs than in the Australian market. As such, Staff determined that a lower system-wide offer cap would be appropriate for the ERCOT market.

Annual resource adequacy cycle. One of the goals of an energy-only resource adequacy mechanism is to incent long-term bilateral contracting and reduce the reliance of LSEs on the ERCOT spot market for serving their load. By starting on October 1 of each year, it is very likely that the high offer caps would be in place during the summer peak to allow resources the possibility of earning inframarginal profits during the summer.

Resource-specific offer caps. A key difference between the Australian market and the upcoming Texas Nodal market is the treatment of local (non-competitive) constraints. The strawman anticipates that ERCOT will ensure that load is protected from abuse of local market power while providing a scarcity pricing mechanism when system-wide conditions merit high market clearing prices in a way that is consistent with Substantive Rule 25.502(g).

Trigger for LCAP. The SPM measures the amount of profit above operating costs that new peaking generation resource would have earned during an annual resource adequacy cycle if it had continuously offered ERCOT its entire output into an ERCOT-procured energy market. When those profits equal the annual fixed cost of a new peaking generation unit, the IMM resets the system-wide offer cap to the LCAP for the remainder of the annual resource adequacy cycle.

Subsection (j) *Authority to enter into capacity adequacy resource (CAR) contracts to sustain reliability*. This subsection describes a backup mechanism for ERCOT to purchase resources to maintain system-wide reliability. A comparable mechanism is used in the Australian market. Comments on individual subsections are as follows:

(j)(3) -The requirement to have ERCOT contract two years out for generation is to ensure contestability for new and existing generation to reduce market power concerns in procuring a generation resource to meet system-wide reliability needs.

(j)(4)(i) – The must-offer provision at the system-wide cap allows ERCOT to meet its reliability needs without depressing scarcity pricing when the resource is deployed.
(j)(4)(ii) – The termination of the interconnection agreement between an existing resource and ERCOT is necessary to reduce the possibility of existing generation resources to use the threat of physical withholding as a means to game the CAR contracting process. The strawman does not impose a similar restriction on new generation resources, as they would likely be in a position to be competitive in the market and in most cases would just enter the market directly rather than being awarded a CAR contract.
(j)(4)(iii) – A reliability problem may occur if a resource owner decides to retire a plant without a two-year notice that would be reflected in a previous SOO or PASA that would signal to market participants that new generation resources would be needed in the market. As with RMR contracts that address local reliability, this strawman proposes a means for ERCOT to offer a CAR contract to a resource that might be needed for system reliability. Such a resource would be compensated with a cost-plus contract to discourage gaming of the CAR contracting process by exerting market power to get a substantial guaranteed return from the CAR contract rather than trying to earn revenue through offers that reflect the generation resource's operating and fixed costs.
(j)(5) – This subsection allows ERCOT to credit those LSEs that have contracted or self-arranged resources to reduce or avoid their uplifted costs of CAR contracts. The specific provisions of this mechanism, while being left to ERCOT to develop, should have as a goal the elimination of free riding of procuring resources and promotion of long-term bilateral contracting between resources and load.
(j)(6) – The additional risk for a load-serving entity that needs to pay for a portion of a CAR contract should be reflected in its ERCOT credit standing. As such, the potential impact would encourage LSEs to increase their bilateral contracting.

Subsection (k) ***Development and implementation***. Staff has no comments.

Change in Substantive Rule 25.502 (d) and (h). As part of this strawman proposal, Staff proposes to change relevant parts of S.R. 25.502.

Workshop and Deadline for Comments

Staff will be hosting a workshop to discuss the details of the strawman on Wednesday, September 14, 2005 at 9:30 am at the Commissioners' Hearing Room, 7th Floor, William B. Travis Building, 1701 North Congress, Austin, TX 78701.

The deadline for comments on the Resource Adequacy strawman is Wednesday, September 21, 2005.

Questions for Stakeholders

1. Subsection (e), *Publication of Resource and Demand Inputs to ERCOT Markets.* A key goal of this rulemaking is to make the operations of ERCOT markets more transparent to market participants. Within the industrial organization academic literature, however, there is a body of work that suggests that tacit collusion may occur if disaggregated market information is published shortly after the clearing of a market. (See attached)

    a. How substantial is the risk of tacit collusion in ERCOT markets? Please give the reasoning behind your position and how the characteristics of the ERCOT market influence your position.
    b. When should the disaggregated market information be published to meet the goals of market transparency without facilitating tacit collusion? Should the timing of publishing aggregated and disaggregated market inputs differ? If so, why?

2. Subsection (h) *Improving the Price Responsiveness of Load*. The strawman lists two tasks that ERCOT shall undertake as part of its review of improving the price responsiveness of load. What other things related to the promotion of demand resources do you believe the Commission should order ERCOT to review?

3. Subsection (i), *Scarcity Pricing Mechanism (SPM)*
    a. Are the levels for the HCAP and LCAP appropriate for encouraging long-term bilateral contracting between load-serving entities and resource owners?
    b. Will the levels for the HCAP and LCAP provide sufficient revenues for owners of new peaking generation units to recover their fixed costs?
    c. Does the threshold for switching from the HCAP to the LCAP provide sufficient incentives to ensure adequate planning reserves for ERCOT?
    d. Does the SPM provide sufficient protection for load?

    If your answer is "no" to any of the questions above, please suggest alternatives and provide your reasoning for them.

4. Subsection (j), *Ability to Enter into Capacity Adequacy Resource (CAR) Contracts to Sustain Reliability*

    a. Will CAR contracts provide an adequate backstop to assure system reliability?
    b. Will the terms of the CAR procurement and deployment prevent strategic mothballing of generation resources?
    c. What, if any, additional necessary conditions should an LSE meet to be exempted from part or all of the uplifted costs of a CAR contract?

5. Do you believe that the transition plan and implementation date of the proposed rule will be timely and effective? If not, please provide alternatives and your reasons why your alternative is better.

Substantive Rule 25.505. Resource Adequacy in the Electricity Reliability Council of Texas Power Region

(a) General. The commission and the Electric Reliability Council of Texas (ERCOT) shall establish mechanisms that provide for resource adequacy to be achieved through an energy-only market design. The mechanisms shall encourage market participants to build and maintain a mix of resources that sustain ERCOT reliability through such means as hedging, long-term contracting between resources and load, and price responsiveness of load.

(b) Statement of opportunities (SOO). ERCOT shall publish an SOO on or around October 1 of each year that provides market participants with a projection of the ability of existing and planned resources, including load resources, and transmission facilities in ERCOT to meet ERCOT's projected electricity demand and system reliability needs over the next ten years. At a minimum, resource entities and transmission service providers (TSPs) shall report to ERCOT their plans for adding new facilities, upgrading existing facilities, and mothballing or retiring existing facilities.

(c) Projected assessment of system adequacy (PASA). ERCOT shall provide market participants with information to assess the adequacy of resources and transmission facilities to meet projected demand in the following two reports:

(1) Medium-Term PASA. Each week, ERCOT shall publish a Medium-Term PASA for each week of the subsequent two years beginning with the week after the Medium-Term PASA is published. Each Medium-Term PASA shall, at a minimum, include the following information:
- **i.** Load forecast by ERCOT zone or area;
- **ii.** Ancillary capacity service requirements;
- **iii.** Transmission constraints, including planned outages; and
- **iv.** Aggregated information on the availability of resources, including load resources.

(2) Short-Term PASA. Each day, ERCOT shall publish a Short-Term PASA for each hour for the seven days beginning with the day the Short-Term PASA is published. Each Short-Term PASA shall, at a minimum, include the following information:
- **i.** Load forecast by ERCOT zone or area;
- **ii.** Ancillary capacity service requirements;
- **iii.** Transmission constraints, including planned outages; and
- **iv.** Aggregated information on the availability of resources, including load resources.

(d) Filing of resource and transmission availability information with ERCOT. ERCOT shall determine the inputs it needs from TSPs and resource entities to prepare PASAs and shall set the timetable that TSPs and resource entities shall follow in updating inputs for PASAs. At a minimum, the following information shall be filed with ERCOT:

(1) Transmission outages. TSPs shall provide ERCOT with information on planned and forced transmission outages.

(2) Resource outages. Resource entities shall provide ERCOT with information on planned and forced resource outages.

(3) Availability of resources. Resource entities shall provide ERCOT with a complete list of resource availability and performance abilities, such as, but not limited to:

i. the net dependable capability of generation and load resources;

ii. projected output of non-dispatchable resources such as wind turbines, run-of-the-river hydro, and solar power; and

iii. output limitations on resources because of fuel or environmental restrictions.

(e) Publication of resource and demand inputs to ERCOT markets. As part of its responsibility to provide transparency to the operation of ERCOT markets, at a minimum ERCOT shall publish the following information:

(1) Aggregated offer and bid curves. ERCOT shall publish the following information 48 hours after the market has closed:

i. Aggregated hourly resource offer information for energy and ancillary capacity service as well as aggregated energy offers for every time interval made within each zone. ERCOT shall publish the aggregated offer curves of offers from all resources, including virtual and load resources, made within a load zone.

ii. Aggregated hourly demand bid information. ERCOT shall publish the aggregated day-ahead bid curves from all loads, including virtual loads, and realized demand for each time interval, made within a load zone.

iii. Dynamic scheduling. ERCOT shall publish the aggregated load and resource output for all entities that dynamically schedule their resources with a load zone.

iv. Bilaterally scheduled hourly load. ERCOT shall publish the aggregated hourly firm bilaterally scheduled load and hour bilaterally scheduled load with “up to” limits on congestion charges made within a zone.

v. Self-provided reserves. ERCOT shall publish aggregated hourly self-provided ancillary services capacity by type of capacity within a zone.

(2) Disaggregated offer and bid curves. ERCOT shall publish the following information 48 hours after the market has closed:

i. Resource-specific offer information. ERCOT shall publish the offer curve for all resources and virtual offers and all other resource-specific information for each resource at each settlement point and settlement interval. The information published shall be clearly linked to the name of the resource, the name of the entity submitting the offer, and the name of the entity controlling the resource. If there are multiple offers for the resource, then ERCOT shall publish similar information for each offer for the resource, including the name of the entity submitting the offer and the name of the entity controlling the resource.

ii. Load-specific bid information. ERCOT shall publish the bid curve for each load and virtual demand bids for each resource at each settlement point and settlement interval. The information published shall be clearly linked to the name of the load, the name of the entity submitting the offer, and the name of the entity controlling the load.

iii. Dynamic scheduling. ERCOT shall publish the load and resource output for each entity that dynamically schedules its resources.

iv. Bilaterally scheduled hourly load. ERCOT shall publish the disaggregated hourly firm bilaterally scheduled load and hour bilaterally scheduled load with "up to" limits on congestion charges made within a zone.

v. Self-provided reserves. ERCOT shall publish disaggregated hourly self-provided ancillary services capacity by type of capacity within a zone.

vi. Virtual offers and bids. In publishing disaggregated information related to offer and bid curves, ERCOT shall identify which offers and bids were virtual.

(f) Approval of planned transmission and generation outages. ERCOT shall approve all transmission and generation outages. When ERCOT decides whether to approve outages, it shall consider their impact on reliability, the outage costs to TSPs and production costs of resource entities, and costs to markets that ERCOT operates.

(g) Credit standards for load-serving entities. ERCOT shall maintain credit standards for load-serving entities (LSEs) or qualified scheduling entities that are consistent with this section.

(h) Improving price responsiveness of load. ERCOT shall work with market participants to create the necessary conditions for, and remove impediments to, price response by load. As part of this process, ERCOT shall file progress reports at the Commission six, eighteen, and thirty months after the implementation of this rule that identify impediments to price response by load, proposed solutions that address those impediments, and progress made in removing those impediments. As part of the report, at a minimum, ERCOT shall:

(1) Conduct a review of the compatibility of existing load profiles with market-based demand-side offerings by LSEs, such as time-of-use pricing and direct load control programs; and

(2) Estimate the incremental costs of installing interval data recording meters for commercial and industrial customers that use load profiles for settlement.

(i) Scarcity pricing mechanism (SPM). The Independent Market Monitor (IMM) selected by the commission pursuant to Texas Utilities Code Section 39.1515 shall administer an SPM that allows resource entities reasonable opportunities to recover their operating and fixed costs through bilateral contracting and ERCOT-operated ancillary service energy and capacity markets. The IMM shall file for commission approval its proposed SPM and any subsequent proposed changes. The SPM shall commence on October 1, 2007. As part of administering the SPM, the IMM shall undertake following:

(1) **Annual resource adequacy cycle**. The IMM shall apply the SPM on an annual resource adequacy cycle, starting on October 1 of each year and ending on September 30 of the following year.

(2) **Peaking generation operating cost (PGOC).** The IMM shall estimate the hourly short-term operating costs of a new peaking generation unit.

(3) **Peaking generation fixed cost (PGFC).** The IMM shall estimate the annual fixed cost of a new peaking generation unit.

(4) **Peaking generation profit margin (PGPM)** The IMM shall track the PGPM, which are the earnings above the PGOC enjoyed by a peaking generation unit that would have offered its entire output into ERCOT-operated ancillary service energy markets since the beginning of the annual resource adequacy cycle.

(5) **System-wide offer caps**. The IMM shall administer the system-wide offer caps as follows

- **i.** On October 1, 2007, the IMM shall set the high system offer cap (HCAP) at $3,000 per megawatt-hour (MWh) and $3,000 per megawatt (MW) per hour. The IMM shall set the low system offer cap (LCAP) at $500 per MWh and $500 per MW per hour.
- **ii.** On October 1, 2008, the IMM shall set the HCAP at $4,000 per MWh and $4,000 per MW per hour.
- **iii.** Beginning October 1, 2009, the IMM shall maintain the HCAP at no lower than $3,000 per MWh and $3,000 per MW per hour and at no higher than $5,000 per MWh and $5,000 per MW per hour.
- **iv.** The IMM shall maintain the LCAP at no lower than $300 per MWh and $300 per MW per hour and at no higher than $700 per MWh $700 per MW per hour.
- **v.** On October 1 of each year, the IMM shall set the system-wide offer cap equal to the HCAP and maintain the HCAP at this level as long as the PGPM during an annual resource adequacy cycle is below the PGFC. If the PGPM exceeds the PGFC, the IMM shall

reset the system-wide offer cap at the LCAP for the remainder of the annual resource adequacy cycle.

(6) **Resource-specific offer caps**. The IMM shall set an offer cap for each resource that protects load from abuse of local market power on transmission constraints that are deemed to be non-competitive.

(7) **Annual report.** The IMM shall conduct an annual review of the effectiveness of the SPM and file a report on that review with the Commission by June 1 of each year. The report shall include the following information:

i. Recommendations for the levels of the system-wide offer caps, PGOC, and the PGFC, that would be consistent with the entry and maintenance of sufficient resources to sustain ERCOT reliability, while preventing transfers of money from LSEs to resource entities that are in excess of those needed to maintain resource adequacy.

ii. A review of all market mitigation mechanisms, including local market power mitigation procedures, with any recommended changes that would ensure the consistency of such mechanisms with the SPM.

This paragraph does not preclude the IMM from requesting commission approval of changes to the SPM at other times.

(j) Authority to enter into capacity adequacy resource (CAR) contracts to sustain reliability. If the resource adequacy mechanisms are at serious risk of substantially failing to provide ERCOT with sufficient amount of resources to serve system-wide load and provide operating reserves to maintain system-wide reliability, ERCOT may enter into CAR contracts to procure sufficient energy and operating reserves. ERCOT shall enter into CAR contracts pursuant to this subsection using the following procedures:

(1) The contracts shall have terms no shorter than 90 days but no longer than five years.

(2) ERCOT shall use the information provided in the PASAs as a benchmark for entering into a CAR contract.

(3) ERCOT shall purchase the services of any generation resource, including a new generation resource, at least two years prior to its use under the CAR contract.

(4) Generation resources are subject to the following terms and conditions for CAR contracts with ERCOT:

i. ERCOT shall require that a generation resource awarded a CAR contract have a must-offer requirement for the period of the contract with the offer curve set at the system-wide offer cap.

ii. The interconnection agreement between ERCOT and an existing generation resource shall terminate at the expiration of the CAR contract. The resource entity may reapply for an interconnection agreement to take effect eighteen months after the expiration of the

CAR contract. The interconnection agreement between ERCOT and a new generation resource that entered the market as part of a CAR contract will not be impacted by the expiration of the CAR contract.

iii. The owner of an existing generation resource must notify ERCOT at least 90 days before the potential retirement of the resource so that ERCOT can evaluate if ERCOT needs the resource to maintain system-wide reliability. If ERCOT deems it needs the generation resource, ERCOT shall enter into a contract with the resource owner up to 640 days. ERCOT shall provide the owner of the resource with cost-plus pricing for using the generation resource. Any money the resource owner makes from being deployed in the market above the cost-plus terms in the CAR contract will be refunded to load on an ERCOT-wide load ratio share basis.

(5) ERCOT shall uplift the costs of the CAR contracts on an ERCOT-wide load-ratio share basis, except that LSEs that can demonstrate to ERCOT that they have through ownership or firm contracts covered all or a portion of their load using resources dedicated to serving that load for the life of the CAR contract are exempt from the uplift for the amount of load so covered.

(6) ERCOT shall take into account current or potential uplift charges associated with this subsection in complying with subsection (g).

(7) This subsection does not limit ERCOT purchases for other reasons, such as the following:

i. routine purchases of ancillary capacity services and energy in the ERCOT day-ahead and real-time markets;

ii. reliability unit commitment (RUC);

iii. black-start service; and

iv. reliability must run (RMR) contracts that address local reliability concerns.

(k) Development and implementation. ERCOT shall use a stakeholder process to develop protocols that comply with this section. ERCOT shall file the protocols by February 1, 2007, for approval by the Commission. Nothing in this section prevents the commission from taking actions necessary to ensure that system reliability in ERCOT is sustained, including actions that are otherwise inconsistent with the other provisions in this section.

§25.502. Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas.

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~~(d) **Disclosure of offer prices.** ERCOT shall publish on its market information system:~~

~~(1) no later than noon of the following calendar day, the identities of all entities submitting offers for which the energy offer price was $300 per megawatt-hour (MWh) or higher, or the capacity offer price was $300 per megawatt per hour (MW/h) or higher, and the corresponding settlement intervals and market locations;~~

~~(2) no later than noon of the following calendar day, the identity of any entity whose offer sets a price for energy above $300/MWh (along with the corresponding settlement interval and market location) and the identity of any entity whose offer sets a price for capacity above $300/MW/h (along with the corresponding settlement interval and market location); and~~

~~(3) concurrent with the publication of a corrected market clearing price, the identity of any entity who is paid more than the market clearing price for the service and the corresponding settlement interval and market location.~~

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(h) **System-wide offer cap.** A supply offer shall not exceed $1,000/MWh or $1,000/MW/h before January 1, 2007. On January 1, 2007, a supply offer shall not exceed $2,000/MWh or $2,000/MW/h until this subsection expires upon the implementation of the system-wide offer caps in §25.505(i)(1).

ATTACHMENT 2

PROJECT NO. 24255

RULEMAKING CONCERNING PLANNING RESERVE MARGIN REQUIREMENTS	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

COMMENTS OF CONSTELLATION ENERGY GROUP, INC. ON COMMISSION STAFF'S RESOURCE ADEQUACY STRAWMAN

Constellation Energy Group, Inc.[1] ("Constellation") appreciates the opportunity to submit these comments on the proposed resource adequacy strawman filed by Commission Staff ("Staff") in this proceeding on August 19, 2005. Constellation is a strong supporter of vibrant, competitive wholesale and retail energy markets where buyers and sellers can both see and respond to price signals that incent adequate resource investment and appropriate demand response.

Constellation appreciates the long-term vision that has led the Public Utility Commission of Texas ("Commission") to adopt policies in the past and a preliminary decision in the instant proceeding that relies solely on an energy-only market to encourage sufficient investment in new and existing generation resources to maintain long-term reliability of the system. While Constellation wholeheartedly supports the Commission's goals with regard to resource adequacy, our extensive experience in other competitive electric markets has convinced us that the best way to achieve such an investment in new and existing generation resources, while at the same time ensuring and maintaining the reliability of the system, is to include well-designed demand curve based price signals as the "reliability backstop" mechanism to complement an energy-only

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[1] Constellation is involved in electric generation, wholesale and retail energy marketing and risk management in competitive electric markets across the U.S., including Texas.

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market. Our comments, therefore, are offered to assist the Commission in developing the package of regulatory policies, rules and mechanisms that can ensure the long-term success of competitive wholesale and retail markets in ERCOT. Thus, based on our broad experience in competitive energy markets nationwide, Constellation's comments below suggest enhancements and revisions to the strawman that we believe will improve the Commission's approach to resource adequacy.

I. Proposed Energy-Only Resource Adequacy Mechanism

Constellation agrees with the Commission that an energy-only market that produces economically efficient prices and ensures reliability should ideally be the goal of the design of competitive energy markets. Organized energy markets must be designed to allow scarcity pricing while providing regulators with the appropriate tools to address the abuse of market power by any market participant. An energy-only market, however, depends heavily on the ability of energy prices to rise in times of scarcity to levels that signal the need for new market entry by generators and demand response. Because of the wide-spread imposition of price caps and other mitigation mechanisms that disrupt price signals, there has been a recognition in other jurisdictions that energy market design needs to include a capacity component to replace the revenues lost through mitigation and thus ensure the required level of reliability.

There is, of course, an inverse relationship between energy prices and the amount of generating capacity in the system in an energy-only market. When a market has "excess" capacity, energy prices should be relatively low and, as it should be, new entry will likely be uneconomic.[2] As the amount of generating capacity, and thus reserve margins shrink, scarcity drives prices up to the point where investment in transmission, generation and investment in demand response can be supported.

As an example, to encourage new generation development, the market price must not only recover the short run marginal cost of the plant, but must recover all other operating expenses, the cost of capital and some profit for investors. A commonly used industry number to represent this cost for simple cycle combustion turbines is \$80,000/MW-yr.[3] In the life cycle of the unit, it must receive \$80,0000 annually above short run marginal costs for each megawatt in size in order to be profitable. The revenues supporting this investment come from market payments for energy, capacity and ancillary services. When these revenue streams rise to a level that appears to be sufficient for investment <u>and</u> appears to be sustainable over the life cycle of the plant, investment can be anticipated.

However, U.S. regulators and policymakers have been uncomfortable letting the market reach its own natural equilibrium, primarily due to concerns that sufficient market response will not moderate rising prices, and that increased prices at that equilibrium level will not be tolerated by consumers.[4] Thus, capacity payments have become a

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[2] Of course, not all generating resources are fungible and regulators need to ensure that proper price signals are sent for the type of resource needed. Price signals for base-load resources, for example, might not produce the quick start capability needed on the system.

[3] This is the number used by Staff. See Transcript of September 14, 2005 Workshop in PUC Project No. 24255 ("Tr.") at 77.

[4] For instance, working with the previous example and the rule's potential maximum price cap of **\$5,000/MWh**, prices would have to remain at this cap for **16 hours** or some combination thereof of lower prices and increased hours that result in the same revenues. In comparison, during the ice storm in February 24 and 25, 2003, prices only reached a level **approaching \$1,000/MWh** for a total of **7 hours.** A major retailer defaulted, resulting in millions of its debt to be borne by the rest of the market, lawsuits against generators who received the revenues, and investigations by the Wholesale Market Oversight division.

common feature in other organized energy markets and, in fact, were implicit in the demand charge component of retail rates in the traditional rate regulated model.

Competitive wholesale electricity markets in the U.S. were originally designed to rely on energy-only prices to send accurate, local price signals to suppliers and load. Although the organized markets in PJM, NEPOOL and New York had historically included capacity products in some form, their first competitive wholesale market designs were based on the premise that investment decisions were to be driven by energy price signals and spark spreads. Moreover, in the summers of 1998 and 1999, spot energy prices in the Midwest, which at the time lacked an organized wholesale energy market, increased significantly for brief periods in response to a severe scarcity of supply. As a result, in response to those price signals, entities, including Constellation, constructed significant new generation resources in the Midwest.

However, in recent years, energy price mitigation, in many forms, has become the norm, depressing the price signals that would otherwise result in both demand response and generation investment when and where necessary. The most recent State of the Market Report for ERCOT ("2004 SOM") shows that net generator revenues, although substantially higher in 2003 and 2004 than in 2002, were less than half of the amount necessary to support new investment in 2004.[5] The 2004 SOM attributes this shortfall to a healthy reserve margin (significantly reduced since the period covered by the 2004 SOM by a more realistic representation of mothballed plants and the dependability of wind capacity in ERCOT's revised reserve calculation methodology). There are

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[5] *2004 State of the Market Report for the ERCOT Wholesale Electricity Markets*, Potomac Economics, Ltd., July 2005 at 44.

additional factors contributing to the current poor investment environment in ERCOT including: the Modified Competitive Solution Method ("MCSM" - which acts as an *ex post* adjustment to competitive balancing energy prices), the $300/MWh "shame cap" (the bid level which causes the bidder's name to be published publicly), and a dysfunctional zonal market design that places significant commitment and operation risk on asset owners.

It is against this backdrop that Staff's proposed energy-only resource adequacy mechanism is designed to be implemented beginning in January, 2007. Constellation has concerns that, particularly in conjunction with the market power mitigation rule proposed in Project No. 29042, the existing MCSM and shame cap, as well as the uncertainty surrounding many aspects of the Wholesale Market Enforcement Rules, that the strawman proposal (1) will not result in sufficient revenues to keep existing resources in the market, much less encourage new investment, (2) will not include sufficient incentives for loads to enter into contracts with resources rather than relying on the balancing energy market, and (3) fails to ensure that sufficient—and <u>essential</u>—demand response will be created.

Constellation submits that whether and how an effective energy only market structure can be implemented must include the following considerations:

1. **Mitigation policy**. Price mitigation can take many forms. In addition to offer and bid caps that are too low, Reliability Must Run ("RMR") contracts (except in very narrow cases where reliability is directly jeopardized), automatic mitigation pricing, cost-capping for out-of-merit dispatch and market rules that prevent demand response from setting the market clearing price, can all distort and dampen price signals. In a

market where market based energy and ancillary services prices alone provide the necessary price signals for investment and demand response, the full and durable elimination of either *ex ante* or *ex post* energy price mitigation is necessary and critical for success. These measures must therefore be eliminated (or sparely applied in a limited, narrowly-targeted manner) in an energy only market construct. When identified, market power abuse should be resolved *ex-post* and on a case-by-case basis.

Offer caps and other forms of mitigation provide a "free" regulatory hedge against high prices, dampening price signals and discouraging market participants from engaging in commercial risk mitigation activity such as long-term contracts. Ultimately, these hedges are not free; they will lead to insufficient investment in generation supply and demand response that ultimately must be addressed by regulators. The resulting absence of market based increases in capacity resources when they are needed may cause regulators to respond to the reliability issues that are created through increased intervention in the markets in form of mandated, rate-regulated responses, because those are the only tools they have once reliability is threatened.

The Commission should guard against such an outcome here, as the proposed strawman, in conjunction with the market mitigation mechanisms proposed in Project No. 29042, ERCOT price administration, the MCSM, the "shame cap," and the cost-capped out of merit deployments by ERCOT, may not allow prices to actually rise in times of scarcity. The success of the strawman proposal, however, is premised on scarcity prices (along with ancillary services revenues) providing sufficient compensation to allow a gas-fired peaker to recover its revenue requirements on an annual basis. Constellation urges the Commission to consolidate this resource adequacy rulemaking proceeding with

Project No. 29042 and any other proceeding in which market price mitigation mechanisms are proposed to be adopted or eliminated, so that the critical interaction among these important elements of an energy only market can be analyzed and considered together. Absent that, Constellation urges the Commission to take into account the various forms of mitigation present in ERCOT in considering whether to accept the strawman proposal.

Constellation recognizes that safety net bid caps may be inevitable. The proposed regulatory caps in the strawman, however, are based on no study or analysis as to either (a) whether they are sufficient to allow scarcity pricing to provide adequate compensation to peaking generation or (b) whether they represent the price level that demand is willing to pay to avoid being curtailed. Constellation suggests that the Commission should perform more rigorous analysis than that described in the preamble to the strawman before determining the appropriate levels of price caps to include in the rule.

For an energy-only market construct to work, investors must have confidence that the energy-only market will be politically durable. That is, the industry needs confidence that market rules won't be significantly changed and new forms of *ex ante* or *ex post* price mitigation instituted in response to elevated or volatile market clearing prices. Policy makers must be prepared to resist the urge to call for mitigation in response to instances of high prices. Thus far, no organized markets in the U.S. have eliminated safety net bid caps and other forms of local mitigation measures, nor can any state or federal regulatory authority ensure that such measures would not be re-introduced even if they were eliminated. For these reasons, Constellation believes that the construct of the reliability backstop is critical to ensuring the long term success of the Texas competitive model.

2. **Long-term contracting**. The key to sustainable resource adequacy in an energy only market is to ensure that the energy-only market is producing price signals that will stimulate investment when necessary and will encourage load and the entities that supply them (the LSEs) to enter into long-term contracts with generators, wholesale suppliers or customers (for demand response) to manage the risks associated with their load serving obligations. In order to function, these forward price signals must demonstrate that sufficient compensation exists for a gas-fired peaker plant to recover its revenue requirements on an annual basis. LSEs must also observe forward price signals and real time price volatility. The risk of volatile prices will naturally drive LSEs to enter into contracts that support generation ad equacy and demand response when needed. Short-term price volatility is a natural feature of any well-functioning commodity market and price volatility sends efficient price signals to resource investors, encourages demand response and promotes bilateral contracting. Market participants need to face exposure to this natural short-term volatility in the market, and be provided a variety of hedging tools, including bilateral contracts, to enable them to hedge such exposure. The final rule, therefore, must contain features to ensure that LSEs have the right incentives to manage their price risks through contracts and discourage excessive reliance on the balancing energy market. The proposed strawman fails to provide the appropriate incentives to ensure that LSEs have the right incentives to manage their price risks, especially when considered in conjunction with existing market price mitigation mechanisms, as well as those proposed in Project No. 29042.

Therefore, the final rule must contain such incentives to allow LSEs to manage their price risks through contracts and discourage excessive reliance on the balancing energy market.

3. **Demand response.** Although Staff correctly recognizes that increasing the responsiveness of demand is critical to the success of an energy-only resource adequacy mechanism, nothing in the strawman ensures that the capability of demand to respond to price will be in place prior to the implementation of such a market in ERCOT. The strawman merely requires ERCOT to "work with market participants to create the necessary conditions for, and remove impediments to, price responsiveness by load," and to file progress reports with the Commission at certain times subsequent to the implementation of the energy only market mechanisms.

4. **Functional backstop mechanism.** While the strawman eschews capacity markets, it in fact includes a capacity mechanism in the form of the Capacity Adequacy Resource ("CAR") contracts that ERCOT is allowed to enter into to maintain reliability. As discussed further below, Constellation is concerned that the proposed CAR mechanism will have several unintended consequences, the most serious of which is that it will end up undermining the efficacy of the energy-only market that is envisioned in the strawman.

Specifically, the CAR proposal represents an improper regulatory intervention in the market. The strawman contains several other forms of regulatory intervention, such as the administratively-determined Peaking Generation Profit Margin (which results in a regulated rate of return for peakers), and administratively-determined market price caps. Each of these proposed regulatory interventions will compromise the success of the energy-only market that the strawman envisions for Texas. The PGPM and administratively-set price caps compromise the energy-only market concept by eliminating true scarcity prices, while the CAR contract moves away from the energy-only market by introducing the equivalent of a capacity market, just what the energy-only construct is intended to avoid.

During the workshop, the CAR mechanism was described as a "spare tire" that should only be used in emergencies. Constellation believes that, for any backstop method, the market, not the market administrator, should be the primary driver of any investment decision. Moreover, as with a spare tire, the most important feature of any backstop is that it is workable if it is needed. Significantly, the CAR mechanism is fundamentally flawed in several respects:

- The CAR mechanism would allow ERCOT, at its own discretion, to enter into contracts with selected parties to either maintain existing capacity in operation on the system or with new entities to construct new capacity. This purchased capacity is then required to submit bids at the maximum offer cap for the duration of the contract. This bidding requirement is done to avoid improper distortion of the offer curve; however, there is also little chance that the capacity will be struck for energy in the market. This requires the entity to be paid up front for all costs to build the plant (in the case of new construction), and maintain the plant in operational condition for the term of the contract. In most cases, this will require ERCOT to pay out tens if not hundreds of millions of dollars for capacity that will likely not be called upon.

- Adding to these problems, when the term of the CAR contracts expire, the market is left with capacity (in the case of new capacity) that has achieved full recovery of its capacity costs through the CAR contract subsidies, giving it a significant competitive advantage in the ERCOT energy market that will likely depress energy prices. This leaves other entities, who constructed their plants in anticipation of strong energy prices, with stranded investment costs when those prices are not realized. Moreover, in a competitive market where there is no direct, subsidized ability for investors to recover these costs from consumers, the end result will be that developers will have to factor in significant risk in their energy forward price forecasts to account for the impact that the CAR contracts will have on the market, both during their term and after. As a result, there will be a chilling effect on new investment, which obviously leads to a greater need for CAR contracts, thereby exacerbating the problem.

- In the case of old capacity, the CAR proposal would claw back all profits made by the owners of such capacity should its price capped bid be struck in the market and attempts made to eliminate the Interconnection Agreement of the generator. It was pointed out in the workshop that many units in ERCOT (especially the older ones) do not have interconnection agreements, and that other interconnection agreements are between the TDSP and the generator and ERCOT is not a party thereto. The proposal would thus attempt to have ERCOT eliminate a contract to which they are not a party.

- This leads to the next major flaw—the cost allocation method for ERCOT's recovery of CAR payments. The strawman provides for a mechanism through which certain loads could avoid payments by demonstrating that they own, or have under contract, capacity to support their load position. As a large percentage of the market falls under this category, ERCOT could wind up with a very small percentage of load paying the millions of dollars associated with these contracts. It is also likely that many loads will not be able to pay such penalties and will default, leaving the rest of the market to pay for the shortfall. In the extreme, if all load makes the required demonstration that they are satisfactorily covered their positions, who will bear the costs of these contracts?

- The CAR proposal also fails to align itself with the primary method of payment for capacity in the market—the energy market. The energy market pays all generators the same amount for the energy delivered. There is no distinction between existing generation or new generation. With the CAR mechanism, there is an attempt to pay only the new capacity on the system, leaving out existing generation. This leads to the problems described above in the second bullet point. A more equitable mechanism would pay all capacity equally in the market.

- The Commission and market participants have taken great care to keep ERCOT out of the financial aspects of the market. In creating the existing market rules, market participants have avoided problems that are created through such mechanisms. The general approach taken in Texas has been to limit ERCOT to managing the operational reliability of the system. The CAR proposal, however, would place ERCOT in the role of a market maker through the release of CAR contracts. In essence, it is ERCOT, not the market, that will determine the level of reserve capacity in the market. Taken to its extreme, ERCOT could create a new over-supply of generation through an overly conservative approach to reliability. ERCOT is a reliability organization. It is ERCOT's job to ensure that all load that does not submit a bid to be curtailed is served, and that the planning and operational reserves are in place to provide such a level of reliable service. ERCOT's natural—and necessary—tendency to be conservative in maintaining an adequate reserve margin will cause it to acquire reserve capacity above the natural level scarcity pricing requires. As discussed above, this "excess" reserve capacity will ultimately depress energy prices and discourage new generation from entering the market unless procured by ERCOT under CAR contracts.

- The CAR proposal forces ERCOT to engage in the equivalent of integrated resource planning to acquire resources under CAR contracts with the combination of geographical, technological and pricing characteristics best suited to maintain reliability. As we know from past experience, while integrated resource planning practices ensure system reliability, they do so at a high price and with the creation of stranded costs.

- Finally, the proposal lacks critical details that must be fleshed out in the rule. The ERCOT stakeholders began developing a capacity market over two years ago in a process that failed to yield enough votes for any proposal to move forward. To return many of these same issues back to the stakeholders will likely result in the same splitting of votes between segments that occurred in the previous process. While it is not desired to be overly prescriptive in the rule, some primary framework needs to be developed in this forum to ensure action occurs.

In order to ensure that the energy-only market construct can successfully meet the infrastructure requirements in Texas, the role of a backstop capacity-only mechanism must be very carefully designed to not undermine the energy-only structure. To accomplish this objective, Constellation urges that the Commission consider substituting a reliability backstop that is designed to work more effectively within an energy-only market. The reliability backstop that Constellation proposes possesses the following key features:

(a) provides revenues only to support the maintenance of resource adequacy;

(b) supports the continued development of competitive retail and wholesale markets;

(c) allows participation by all qualified resources, rewards all capacity as does the energy market;

(d) creates little or no distortions to the energy market;

(e) preserves the independence of ERCOT from the market;

(f) allows maximum flexibility for LSEs to manage their portfolios;

(g) requires that qualified resources are asset-based; and

(h) clearly defines the obligations of resources in the energy market.

Attachment A to these comments describes the Demand Curve Resource Adequacy ("DCRA") approach as an alternative to the CAR contract mechanism that meets these criteria.[6] The DCRA approach is structured so that payments only exist as a supplement to energy payments made to all qualified capacity resources, if needed as an incentive to maintain reliability levels, and the payments are only triggered if capacity levels drop below a reliability level established as reasonable by policy makers. In summary, the DCRA approach works as follows:

- ERCOT annually compares the existing resource base to the forecasted peak load.
- ERCOT, with stakeholder and expert analysis input, develops a demand price curve that establishes the value of capacity resources as a function of the aggregate resources available – the more resources that exist, the lower the value of the aggregate base; as available resources decline, the value goes up.
- When ERCOT identifies that the resource base has gone below the required reserve margin, it announces that a reliability payment pursuant to the demand curve pricing will begin for all qualified resources, existing and new.
- The additional revenue stream paid to generators acts as an incentive for improvements to existing generation and/or construction of new generation that will return the system to the required reserve level.

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[6] The DCRA approach described here is modeled after the demand curve approach to capacity market design that has been implemented in New York, adapted for application within the energy only market structure envisioned by the strawman.

Thus, implementation of the DCRA approach ensures that if the energy-only market provides enough revenue to sustain the market and maintain the required reserve levels, no payment is required and the backstop is not triggered. If not, the DCRA mechanism engages and provides a far less disruptive approach than the CAR contracts proposed in the strawman.

Additionally, the existence of the demand curve provides a signal to the marketplace of capacity value and should serve to incent market participants to forward contract, and provide the basis for robust bilateral negotiations between resources and LSEs. Indeed, while the DCRA approach requires a measured amount of regulatory intervention to establish the demand curve pricing, it also—unlike the CAR—ensures that such regulatory intervention supports and encourages the development of bilateral markets—the key to a successful, and sustainable, energy-only market.

II. Proposed Disclosure Requirements

Constellation supports the increased pricing transparency that nodal market design will provide, as well as the strawman's general concept of publicly disclosing aggregated information in 48 hours. The language in Section (e)(1) (such as "made within a zone"), however, should be clarified to clearly require that numbers be aggregated by zone.[7] The language should also make clear that if the disclosure provision is in effect after a nodal market is implemented, data will be aggregated for all generators by zone based on the load zone from which they take their auxiliary services when the plant is not operational. This is important to avoid discriminatory damage to a generator that has the only plant at a node. The amount of disaggregation, such as

[7] Tr. at 18, 38-39 (Sep. 14, 2005).

whether data remains aggregated by QSE or whether individual QSE-to-QSE transactions are disaggregated is important to consider in relation to the disruption that such disclosure would cause the market.[8]

The strawman's proposed public disclosure of detailed non-aggregated information within 48 hours, however, would damage competition and investment. Staff sees transparency as a trade-off for higher offer caps. Now that reserve margins are shrinking, in actuality adequate generation investment is the trade-off for higher offer caps, and there is concern as it is regarding whether the higher offer caps will be sufficient to induce adequate generation investment. The disclosure contemplated in the strawman would be a disincentive to resource adequacy.[9]

One must first determine if such a release of highly competitive data is useful. The strawman proposes that this transparency is needed for oversight of the market. However, all the disaggregated information is already provided to Wholesale Market Oversight and will be provided to the ERCOT independent market monitor ("IMM") within 48 hours of the trade day. The purpose stated in the preamble for the release of the data publicly is to allow all market participants to take on the role of market monitor. This is an improper assignment to give the market. In any event, market participants already have prompt access to useful data on the ERCOT and Commission websites, and under the Protocols, access to substantial amounts of additional information (including bids and pricing information identifiable to a specific QSE) in six months.[10] Unlike the

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[8] Tr. at 29-30.

[9] Tr. at 31, 34.

[10] *See* ERCOT Protocols §§ 1.3.1.1. and 1.3.3.

staff and the IMM, however, market participants can use disaggregated data they obtain soon after the trading day in an anticompetitive manner.

The strawman is not supported by any analysis of what information, level of disaggregation and timing of release would be particularly helpful to market oversight or particularly harmful to the owner of the information or to competition, or any support for the assumption that the current level of disclosure is inadequate.[11] Dr. Oren commented:

> But Ross is making a point that for each player -- each player needs to know the aggregated information. Because if they know what they did, they know what the aggregated did, they can do the analysis that we're talking about. The market monitor needs to know the fully disaggregate information, but that doesn't necessarily need to be made public to the rest of the population.[12]

It is the disaggregated data, however, that raise the concerns regarding harm to the owner of the information and to competition.

Three additional questions are discussed in more detail below:

- <u>What types of information is the Commission prohibited from disclosing publicly?</u> An example is trade secrets.
- A court recently ruled that the Commission has no authority to order public disclosure of information that a municipally-owned provider of electric utility service ("muni") has found to be a competitive matter. <u>Should the Commission avoid ordering public disclosure of a company's competitively sensitive information?</u>
- <u>How do concerns regarding harm to the owner of the information and to competition, including tacit collusion, affect what and how quickly information should be publicly disclosed?</u>

1. **Types of information that cannot be publicly released.** The Commission has no statutory authority to order public disclosure of competitively sensitive information, including trade secrets and commercial or financial information of

[11] Tr. at 45-46.

[12] Tr. at 44; *see also* Tr. at 45-46.

a person for whom public disclosure would cause substantial competitive harm. On the contrary, the Commission has an affirmative obligation to ensure confidentiality of such information. There are four sources of that legal obligation: the Public Information Act ("PIA"),[13] Texas rules on privilege and protective orders, PURA, and constitutional protections. After discussing these authorities, the procedures that must be used to determine if information should be publicly disclosed and the types of information that are protected are discussed in more detail.

PIA. PIA § 552.352 imposes strong sanctions for distributing information considered confidential under the terms of the PIA:

> (a) A person commits an offense if the person distributes information considered confidential under the terms of this chapter.
> (b) An offense under this section is a misdemeanor punishable by:
> (1) a fine of not more than $1,000;
> (2) confinement in the county jail for not more than six months; or
> (3) both the fine and confinement.
> (c) A violation under this section constitutes official misconduct.

Information considered confidential under the PIA includes "information considered to be confidential by law, either constitutional, statutory, or by judicial decision..." under §552.101 and confidential business information described in § 552.110:

> (a) A trade secret obtained from a person and privileged or confidential by statute or judicial decision . . .
> (b) Commercial or financial information for which it is demonstrated based on specific factual evidence that disclosure would cause substantial competitive harm to the person from whom the information was obtained. . .

Texas rules on privilege and protective orders. The second source of the Commission's obligation is its duty to give effect to privileges. Under PURA §11.007(a),

[13] TEX. GOV'T CODE §§ 552.001-552.353 (Vernon 2004).

the Commission is subject to the Administrative Procedure Act ("APA").[14] APA § 2001.083 requires: "In a contested case, a state agency shall give effect to the rules of privilege recognized by law." Trade secrets are privileged. For example, TEX. R. EVID. 507 states:

> A person has a privilege, which may be claimed by the person or the person's agent or employee, to refuse to disclose and to prevent other persons from disclosing a trade secret owned by the person, if the allowance of the privilege will not tend to conceal fraud or otherwise work injustice. When disclosure is directed, the judge shall take such protective measures as the interests of the holder of the privilege and of the parties and the furtherance of justice may require.

Similarly, under APA § 2001.091 discovery in Commission proceedings is "subject to limitations of the kind provided for discovery under the Texas Rules of Civil Procedure." TEX. R. CIV. PROC. 192.6(b) states: "To protect the movant from . . . invasion of . . . constitutional, or property rights, the court may make any order in the interest of justice..."

Under these laws, if a trade secret is required to be disclosed at all, the disclosure is not public but rather under appropriate protective measures. For example, the Texas Supreme Court has held that when a party resisting discovery shows that requested information is a trade secret, the burden shifts to the requesting party to establish that disclosing the information to it is <u>necessary for a fair adjudication of its claim or defense:</u>

> We therefore hold that trial courts should apply [Texas Evidence] Rule 507 as follows: First, the party resisting discovery must establish that the information is a trade secret. The burden then shifts to the requesting party to establish that the information is necessary for a fair adjudication of its claims. <u>If the requesting party meets this burden,</u> the trial court should ordinarily <u>compel disclosure of the information, subject to an appropriate protective order</u>. In each circumstance, the trial court must

[14] TEX. GOV'T CODE §§ 2001.001-2001.902 (Vernon 2000 & Supp. 2004).

weigh the degree of the requesting party's need for the information with the potential harm of disclosure to the resisting party. [15]

The Court rejected an argument that, to obtain access to a trade secret under protective order, a party need show only that the information is relevant to the proceeding. "However, because relevance is the standard for discovery in general, *see* Tex. R. Civ. P. 166b(2)(a), this approach likewise would render Rule 507 meaningless. Rule 507 clearly contemplates a heightened burden for obtaining trade secret information."[16]

As the above excerpts indicate, when referring to disclosure, the Court did not mean public disclosure. Rather, the issue is whether a trade secret should be disclosed to a party under protective order or instead withheld from the party entirely. (This is also shown by the second sentence of TEX. R. EVID. 507: "When disclosure is directed, the judge shall take such protective measures . . ."). The Court also rejected an argument that trade secrets should be produced in cases that are not disputes between business competitors, holding that this argument "would render the Rule 507 privilege meaningless in noncompetitor cases."[17]

PURA. The third source of the Commission obligation to protect confidential business information is PURA. The strawman at 8 refers to ERCOT having a responsibility to provide transparency to the operation of ERCOT markets. That responsibility is nowhere in PURA. On the contrary, § 39.151(d) requires that ERCOT's procedures be consistent with PURA, and PURA requires protection of competitively

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[15] *In Re Continental General Tire General Tire, Inc., Relator*, 979 S.W.2d 609, 613 (Tex. 1998).

[16] *Id.*

[17] *Id.*

sensitive information. That requirement, which applies to ERCOT and the Commission, is contained in numerous PURA provisions:

- PURA § 14.154 states: "A record obtained by the commission relating to sale of electrical energy at wholesale by an affiliate to the public utility is confidential and is not subject to disclosure under Chapter 552, Government Code."
- PURA § 17.051 states that "reporting requirements for . . . qualifying facilities that are selling capacity into the wholesale or retail market, exempt wholesale generators, and power marketers . . . may not require the disclosure of highly sensitive competitive or trade secret information."
- PURA § 32.101, discussing utility tariffs, states: "The commission shall consider customer names and addresses, prices, individual customer contracts, and expected load and usage data as highly sensitive trade secrets. That information is not subject to disclosure under Chapter 552, Government Code."
- PURA §39.001(b) states: "The legislature finds that it is in the public interest to: . . . (4) protect the competitive process in a manner that ensures the confidentiality of competitively sensitive information during the transition to a competitive market and after the commencement of customer choice."
- With respect to reporting of "information necessary for the commission to assess market power or the development of a competitive retail market in the state," PURA §39.155(a) states that "The commission shall by rule prescribe the nature and detail of the reporting requirements and shall administer those reporting requirements in a manner that ensures the confidentiality of competitively sensitive information."
- PURA § 39.351 states: "A person may register as a power generation company by filing . . . information required by commission rule, provided that in requiring that information the commission shall protect the competitive process in a manner that ensures the confidentiality of competitively sensitive information."
- Regarding certification of retail electric providers, PURA § 39.352(f) states: "The commission shall use any information required in this section in a manner that ensures the confidentiality of competitively sensitive information."

In overturning a rule providing for the Commission to determine the confidential status of information that a muni had determined to be a competitive matter, discussing Senate Bill 7 the Austin Court of Appeals recently held: "One of the foundational principles of this reform is that it is in the public interest 'to protect the competitive process in a manner that ensures the confidentiality of competitively sensitive information.'"[18]

[18] *City of Garland v. Public Utility Commission of Texas,* 165 S.W.3d 814, 816 (Tex. App. – Austin 2005, pet. pending).

Like the Legislature in PURA § 39.001(b), courts have held that protecting confidential business information both protects the owner of the information and serves the public interest. "State trade secret laws and federal copyright and patent laws are backed by similar public policy goals."[19] "The public interest is served by protecting trade secrets."[20]

In *State ex Rel. Utilities Comm'n*,[21] the court reversed the utility commission's order denying protection to information revealing how a company serves its customers, how it plans to enter the local market, how quickly it acquires new customers, in which locations it is focusing its marketing efforts, and the relative effectiveness of those efforts. The commission had argued that trade secrets must be analyzed in light of utility regulatory objectives and the public's need for disclosure:

> the Commission denied the CLP's "Joint Petition for Reconsideration," concluding, *inter alia*, that the trade secret exception to the Public Records Act must be "analyzed within the context of a regulated industry. This means that what may perhaps be deemed to be a 'trade secret' within a totally and freely competitive marketplace should not necessarily be construed to be a 'trade secret' within a regulated marketplace." The Commission also justified its decision stating: "the numerous public interests . . . have a legitimate – and in some cases, a compelling – need for this information." Finally, the Commission cited several broad regulatory powers conferred to it by the General Assembly in support of its "public interest" justification for upholding its decision of public disclosure.[22]

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[19] Patricia A. Meier, *Looking Back and Forth: The Restatement (Third) of Unfair Competition and Potential Impact on Texas Trade Secret Law*, 4 TEX. INTELLECTUAL PROPERTY LAW J. 415, 420 (Spring 1996).

[20] *Picker International, Inc. v. Blanton*, 756 F.Supp. 971, 983 (N.D. Texas 1990) (applying Texas law).

[21] *State ex Rel. Utilities Comm'n v. MCI*, 514 S.E.2d 276 (N.C. App. 1999).

[22] *Id.* at 283.

The court disagreed: "In so holding, we specifically reject the position of the Commission that this exception must be construed differently in the context of a regulated industry."

This Commission made a similar argument in *Garland.* "Believing that 'making certain market-related information available to the public in a timely manner is a necessary part of immunizing a well-tempered marketplace from the dangers of market power abuse,' the Commission adopted rules under utilities code section 39.155(a) to effectuate 'judicious disclosure' of utility wholesale transaction reports."[23] The court was not persuaded, ruling as a matter of law: "Accordingly, we hold that any decision the Commission might make under rule 25.93 as written with regard to a claim of confidentiality under government code section 552.133 would violate its duties under utilities code section 39.155 [requiring that the Commission administer reporting requirements in a manner that ensures the confidentiality of competitively sensitive information]."[24]

Constitutional protections. The fourth source of the Commission obligation to protect confidential business information is the constitutional rights of the owner of the information. The United States Supreme Court determined that, to the extent that a party has an interest in its data cognizable as a trade-secret property right under state law, that property right is protected by the Taking Clause of the Fifth Amendment of the U.S. Constitution.[25] The Court explained that whether a "taking" has occurred is an *ad hoc*, factual, inquiry. Factors considered are:

- The character of the governmental action;

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[23] *Garland,* 165 S.W.3d at 817.

[24] *Id.* at 821.

[25] *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986, 81 L.Ed.2d 815, 104 S.Ct. 2862 (1984).

- Its economic impact; and
- Its interference with reasonable investment-backed expectations.

In considering what investment-backed expectations would have been reasonable, the Court looked to trade secret law under the federal regulatory statute and state law. As noted above, under Texas law there are reasonable, investment-backed expectations that disaggregated information like that released under the strawman will not be publicly disclosed.

Procedure to determine if information is protected. In adopting Rule 25.93, regarding quarterly wholesale electric transaction reports, the Commission recognized that a rulemaking does not provide procedures appropriate for the fact-specific inquiry required by Texas law to determine if specific information should be publicly released:

> Disclosing contract information to the public is a separate issue from reporting it to the commission. . . . The proposed rule, however, contemplates making such a decision (absent an open records request) in a contested docket and not this rulemaking. Similarly, the commission declines to deem current contract information as highly sensitive in this rulemaking, as requested by Reliant. That, too, is more appropriately determined in a contested docket, by the Texas Attorney General, or by the courts. . . . The determination of whether information is competitively sensitive and whether it should be released to the public is therefore a fact intensive question that the commission reserves for a more appropriate venue. . . . The contested-case proceeding is necessary for the commission to establish a factual record to support one of two conclusions of law: that the information is competitively sensitive and must be protected; or that it is not competitively sensitive and may be released.[26]

That determination is indeed fact-specific, as shown by the Texas legal standards. In determining whether information is a trade secret, for example, six factors from the Torts Restatement are considered:

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[26] 28 TEX. REG. 7689 (Sep. 5, 2003).

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1. the extent to which the information is known outside of [the company's] business;
2. the extent to which it is known by employees and others involved in [the company's] business;
3. the extent of measures taken by [the company] to guard the secrecy of the information;
4. the value of the information to [the company] and to [its] competitors;
5. the amount of effort or money expended by [the company] in developing the information; and
6. the ease or difficulty with which the information could be properly acquired or duplicated by others.[27]

The Texas Supreme Court clarified:

> We agree with the Restatement and the majority of jurisdictions that the party claiming the trade secret should not be required to satisfy all six factors because trade secrets do not fit neatly into each factor every time. We additionally recognize that other circumstances could also be relevant to the trade secret analysis. Thus we will weigh the factors in the context of the surrounding circumstances to determination whether [information qualifies] as trade secrets.[28]

Another problem is that the strawman's public release of detailed information would provide no opportunity to seek judicial review before information is disclosed. Recognizing that disclosure destroys the value of the privilege, courts have enjoined Commission and other agency orders requiring disclosure of documents claimed to be privileged.[29] *See also Bass* granting conditional mandamus relief and ordering the trial court to vacate its order compelling the production of data, on the basis that no adequate remedy exists if a party is ordered to produce privileged trade secrets without the showing of necessity required by *Continental General Tire*.[30] An opportunity to seek an

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[27] Open Records Decision 669 at 3, quoting Torts Restatement § 757 cmt. b.

[28] *In re Bass*, 113 S.W.3d 735 (Tex. 2003).

[29] *See, e.g., Pub. Util. Com'n v. Houston Lighting & Power Co.*, 778 S.W.2d 195 (Tex. Civ. App. – Austin 1989).

[30] *Bass; accord Continental General Tire.*

injunction, which has long been provided in Commission protective orders, is also provided in rules like Rule 25.93(g), which states:

> if either the commission or the attorney general determines that the disclosure of protected information is permitted, the commission shall provide notice to the reporting entity at least three business days prior to the disclosure of the protected information . . .

Similarly, a person may file a suit to prevent disclosure of information that is the subject of a PIA request.[31]

Relation of standards to specific types of information. Again, a fact-specific inquiry and opportunity for judicial review are required before public disclosure. Certainly the information that the strawman would disclose publicly after only 48 hours could not be determined as a matter of law not to be protected. Examples of information compilations that courts have held to constitute trade secrets in particular circumstances include customer and client lists, buyer contracts, vendor information, bidding systems, marketing plans and strategies, and pricing information.[32] In Open Records Decision No. 552 at 1, 3 (1990), the Attorney General refused to require public disclosure in a situation in which "the Railroad Commission received an open records request for information that furnishes the names of customers and contracting parties identified only by number in the tariff filings and 1988 annual reports of Lone Star Gas Company and Access Energy Corporation":

> This office has found customer lists to be trade secrets excepted from public disclosure. . . . Lone Star makes it clear that what is at issue is not only the names of customers, but the resultant contract and pricing information which may be ascertained by matching the customer names to

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[31] *See, e.g.,* PIA §§ 552.325 and 552.3215.

[32] Scott D. Marrs, "*Trade Secrets: Preliminary Relief in Trade Secret Cases,*" 61 TEX. BAR J. 880, 882 (Oct. 1998).

> other information in its required filings with the Railroad Commission. We conclude that Lone Star has made a *prima facie* case that the information in question constitutes a trade secret.

Even the Federal Energy Regulatory Commission ("FERC") requires public disclosure of the detailed transaction (not bid) information in its quarterly reports 30 days after the end of the quarter reported – not 48 hours after the interval in question. Bid information like that made public after only 48 hours under the strawman is more competitively sensitive to the entity that made the bid and less significant for other purposes. Moreover, in two respects, FERC's legal basis for requiring public disclosure is stronger than the Commission's. First, the entities whose data the strawman would disclose are not public utilities under PURA. In contrast, even entities like power marketers are defined as "public utilities" in the federal statute and are required to have tariffs on file at FERC.[33] FERC has distinguished its refusal to require public disclosure of <u>non-utilities'</u> individual data:

> The Commission found that gas sellers' contract and transaction data could be considered trade secrets and commercial or financial information and that disclosure is likely to cause substantial harm to the competitive position of the person from whom the information was obtained. The Commission then found that the potential of competitive harm from public disclosure outweighs any public interest in disclosure of data concerning individual sales transactions, and stated that the Commission would not disclose individual sales information to the public. The finding of competitive harm, however, was based on the unregulated nature of much of the data sought there.[34]

Second, Federal Power Act ("FPA") § 205(c) requires public disclosure of information submitted by a public utility such as a power marketer:

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[33] FERC Order No. 2001, *Revised Public Utility Filing Requirements*, 99 FERC ¶ 61,101 (April 25, 2002) at 10, 12-13, and 46.

[34] Order No. 2001 at 43-44.

> But FPA section 205(c) requires public utilities to disclose their rates and contracts for all transmission and sales subject to the jurisdiction of the Commission. As a result, these rate elements as well as the data public utilities currently file are not protected from disclosure under Exemption 4 of the FOIA [federal Freedom of Information Act] or by the Trade Secrets Act. Although the Commission has discretion to determine the time and form for disclosure, the underlying decision to disclose rate and contract information was made by Congress.[35]

In contrast, PURA requires protection of competitively sensitive information and nowhere authorizes the Commission to require disclosure.

In *Continental Oil Co.*,[36] a court overturned an order by FERC's predecessor agency that required public disclosure by interstate natural gas companies of "detailed intrastate sales information, including the names of purchasers, data and location of the sale, pressure base, annual sales volume and price terms." The court explained:

> The information to be furnished is detailed – a contract by contract, field by field exposition of the petitioners' product marketing. Prices, names of purchasers, terms and times of price renegotiation must be disclosed. The likelihood that delivery of these intimate facts to petitioners' competitors would be harmful is apparent. Not only could it affect sales by enabling competitors to learn contract termination dates but it also affects product acquisition. . . . Disclosure of individual field prices will disrupt lessor-lessee relationships where the market value is less than the highest price reported in the area. The compilation and disclosure to petitioners' competitors, purchasers and suppliers of information as to the extent of supply and competitive prices in each market area would alter industry custom and existing relationships to the disadvantage of petitioners' competitive position.
>
> The FPC maintains that the information is not confidential. They point to the fact that at least one state requires public disclosure of data of the type required and that many newspapers and trade journals publish intrastate sales information. This proof falls short of carrying the contention that the

[35] Order No. 2001 at 38. *See also* Order No. 2001 at 32-33, 50-51.

[36] *Continental Oil Co. v. Federal Power Comm'n,* 519 F.2d 31 (5th Cir. 1975), cert. denied *Superior Oil Co. v. Federal Power Comm'n,* 425 U.S. 971, 48 L.Ed.2d 794, 96 S.Ct. 2168 (1976).

broad reach of Order No. 521 is harmless to the business interests of those it affects.[37]

Thus, for all of these reasons, the Commission cannot by rule publicly release the disaggregated information in the manner provided in the strawman.

2. **Discriminatory public release of information.** Harm from release of confidential business information would be even worse if a company's data were released and its competitors' equivalent data were not released at the same time or even at all. The strawman, however, proposes to release within 48 hours data for which *Garland* held the Commission has no authority to require public disclosure for munis. As a matter of law and policy, the statutory provisions should be applied in a consistent and nondiscriminatory manner. PURA § 39.001(c), for example, states: "Regulatory authorities . . . may not discriminate against any participant or type of participant."

Garland concerned PIA § 552.133(b), which states: "Information or records of a municipally owned utility that are reasonably related to a competitive matter are not subject to disclosure under this chapter, whether or not, under the Utilities Code, the municipally owned utility has adopted customer choice or serves in a multiply certificated service area." Subsection (a)(3) states: ""Competitive matter" means a utility-related matter that the public power utility governing body in good faith determines by a vote under this section is related to the public power utility's competitive activity, including commercial information, and would, if disclosed, give advantage to competitors or prospective competitors."

The inconsistency issue also arises regarding PURA provisions still in effect but adopted earlier with different but consistent phrasing. For example, PURA § 14.154

[37] *Id.* at 35.

states that "a record obtained by the commission relating to sale of electrical energy at wholesale by an affiliate to the public utility is confidential and is not subject to disclosure under Chapter 552, Government Code"; PURA § 17.051 states that "reporting requirements for . . . qualifying facilities that are selling capacity into the wholesale or retail market, exempt wholesale generators, and power marketers . . . may not require the disclosure of highly sensitive competitive or trade secret information"; PURA § 32.101, discussing utility tariffs, states: "The commission shall consider customer names and addresses, prices, individual customer contracts, and expected load and usage data as highly sensitive trade secrets. That information is not subject to disclosure under Chapter 552, Government Code."

The PIA and PURA protections for confidential business information are all consistent and should be applied consistently. Moreover, the various statutory provisions provide guidance as to the types of information that the Legislature intended to be protected. For example, the Commission Annual Report Form for Retail Electric Providers (REP) Instructions notes at 2: "Although the exception in Section 552.133 is only available for use by a Public Power Utility, the section includes a list or categories of information that may not be deemed to be competitive information and this list may be instructive to REPs in determining whether their information is likely to be subject to other exceptions under the Act."

3. **Harm to the owner of the information and to competition**. The trade secret privilege exists to protect the interests of the holder of the trade secret.[38] The legal authorities for protection of confidential business information recognize that release

[38] Open Records Decision No. 669 at 2 (2000).

of such information could provide knowledge about a company and its circumstances that could be used to cause that company competitive harm. As discussed above, PURA and other legal authorities for such protections have already found that confidentiality of such information is in the public interest.

Another concern is that raised in the strawman preamble, that knowledge of a competitor's prices would permit tacit collusion. In considering such concerns, FERC has held that bid data should be released after six months – the same period long in effect under the ERCOT Protocol § 1.3.3.

> With respect to the Plan's confidentiality requirement for bid and related data, we note that the commercial sensitivity of such data decreases over time. Consistent with an earlier order concerning the New York Independent System Operator, we direct PJM to make available to the public, bid and other data after 6 months.[39]

In the New York order, FERC concluded "that it would not require the names of bidders to be publicly revealed; it did require, though, that bid data be posted in a way that permits analysts to track each individual bidder's bids over time."[40] FERC also concluded: "we have permitted the information to be kept confidential for six months to help prevent collusive behavior."[41]:

The strawman preamble states at 1: "In a capacity-and-energy resource adequacy mechanism, such as LICAP, a generation resource receives a capacity payment on the condition of a must-offer requirement and mitigated offer curves that are close to the

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[39] *PJM Interconnetion, L.L.C.*, Docket No. ER98-3527-000, Order Approving Market Monitoring Plan as Modified, 86 FERC ¶ 61,247 (Mar. 10, 1999), citing *Central Hudson Electric & Gas Corporation*, 86 FERC ¶ 61,062 at 9 (1999).

[40] *PJM Interconnection, L.L.C.*, Docket No. ER98-3527-002, Order Denying Rehearing, Issuing Clarification and Denying Late Intervention, 88 FERC ¶ 61,274 at 3 (Sept. 21, 1999).

[41] *Id.*

units estimated short-run marginal cost ("SRMC"). Transparency of offer curves in such a situation may not be as critical because of the heavy mitigation involved." That conclusion does not follow. That mitigation is on top of capacity payments does not mean total price will be lower than an energy-only price. That ERCOT has no capacity payments, however, does increase the importance of the regulatory scheme being conducive to adequate generation investment. Disclosure that is too detailed and too quick or discriminatory increases risk in a manner particularly harmful in an energy-only market like ERCOT.[42]

The strawman also notes that the Australian market publishes offer curve information a day after the market closes. In Australia, however, 60 percent of the market participants are government-owned,[43] reducing concerns about tacit collusion, damage to investment incentives, and heightened reputational and other risk from excessive disclosure.[44] In addition, the Commission must follow not Australian law but Texas law, which protects such information.

In conclusion, the strawman's public disclosure of detailed disaggregated data after 48 hours is not needed for the Commission or the IMM to police markets; they will have the data. Market participants have data after a suitable time lag. Unlike speedy disclosure to the Commission or the IMM, speedy disclosure to market participants has anti-competitive impacts. The strawman requirement also exceeds the Commission's statutory authority, would violate legal protections for confidential business information,

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42 *See, e.g.,* Tr. at 31, 34.

43 Tr. at 48.

44 Tr. at 31.

and would apply in an anti-competitive and discriminatory manner. Constellation urges rejection of this provision of the strawman.

Respectfully submitted,

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ATTORNEYS FOR CONSTELLATION ENERGY GROUP, INC.

ATTACHMENT A

Reliability Backstop/Demand Curve

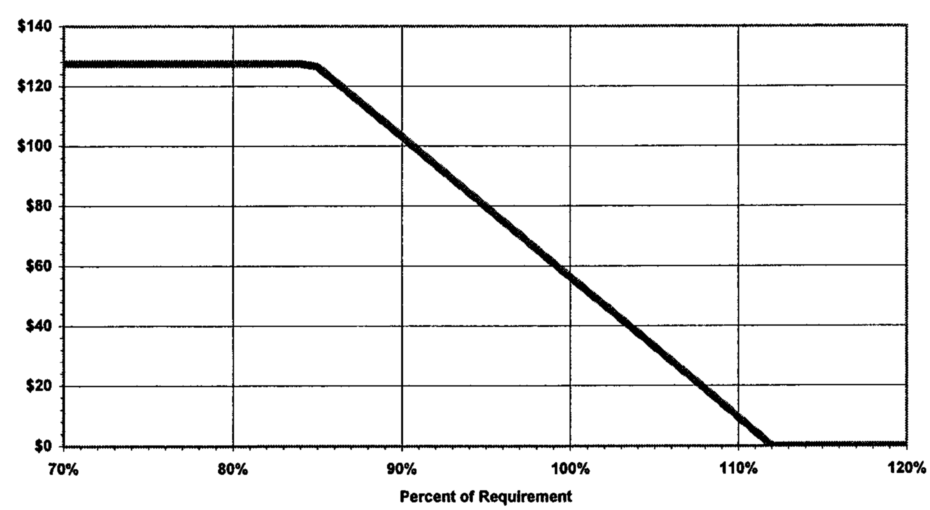
1. What is a demand curve?

A demand curve is an administratively determined, downward sloping, range of prices that reflect the value of capacity. The demand curve clearing price depends on total amount of available resource, contracted for bilaterally or offered in the demand curve auction.

2. How are demand curve prices set?

The demand curve pricing is established by first estimating the cost of new entry and offseting that amount by the estimated energy and ancillary services revenues. This pricing point then corresponds to an aggregate amount of the capacity equal to the required reserve margin level. From this point, a line (or curve) is extended downward to a defined capacity amount in excess of the established reserve margin ("zero crossing point"). The line (or curve) is also extended upward to a point where the ling goes flat (the cap). In order to properly establish and implement demand curve pricing for capacity, it is necessary to recognize that capacity in excess of the single point reserve requirement still has some value, albeit on a declining scale, and that as capacity levels go below the reserve requirement, capacity has an increasing value. Ideally, the demand curve pricing and the appropriate reserve margins are established three to four years in advance and reviewed on a periodic basis.

Sample Demand Curve



AUS:2615184.1
53065.4

3. **How is the demand curve developed?** ERCOT, with stakeholder and expert analysis input, will develop three or four year forward demand curve pricing by which to procure, available, qualified capacity resources.

4. **How does a demand curve work with bilateral contracts?** The demand curve is a means of assuring that holders of capacity resources can commit their capacity to the market and participate in the spot market for capacity if they have not been able to negotiate bilateral contracts, but are willing to accept the demand curve pricing. Likewise, if bilateral contracting does not result in the commitment of capacity ERCOT believes is necessary to reliably serve the market, the demand curve pricing provides an open and transparent pricing mechanism that ERCOT can use when it procurer resources. In this way, the demand curve provides price signals to the marketplace of the value that will be placed on capacity resources in the spot market. Properly set demand curve pricing will incent forward contracting and thus set the stage for robust bilateral negotiations between the owners of capacity resources and load serving entities.

5. **How does the demand curve procurement work?** Three years prior to each trade year ERCOT will determine the level of resources committed to be on line for that trade year and will also forecast the peak load for that year. If aggregate resources are found to be below the require reserve margin levels, ERCOT shall announce that capacity payments will be made to resource holders that bid into a solicitation as long as the offer price is below the demand curve clearing price (i.e, the point on the demand curve that corresponds to the aggregate of the bilaterally committed resources plus the demand curve auction resources). In the trade year, all resources that were committed to be on line for the trade year and those awarded at auction will be paid the demand curve clearing price. The cost of these payments can be allocated to all LSEs on a month-to-month pro rata basis of peak demand in the peak hour of the month or any other reasonable method that best aligns itself with cost causation and the fluid nature of the retail market. LSEs may establish contracts with resource suppliers that allow them to net these payments for secured contracts.

Key Benefits Of Using a Demand Curve for the Reliability Backstop

- **Provides effective backstop to an energy only market:** By having the demand curve adjust downward to reflect rising energy prices, the demand curve underpins the transition to an energy only market and ensures adequate reliability during the transition.
- **Adequate market information:** The demand curve, if needed, ensures that the marketplace is informed about the resource requirement that will be enforced three or four years hence.
- **Establishes a range of market prices:** The demand curve provides a range of market prices that will prevail in the spot market for capacity three years hence, depending on the aggregate size of the resource base.
- **Provides market incentives:** The combination of a known resource requirement and the demand curve pricing will provide the necessary incentives for LSEs and capacity suppliers to enter into bilateral contacts.
- **Ensures that ERCOT remains a market administrator, not a market maker:** By focusing on promoting bilateral markets, ERCOT's primary function of administering markets is preserved.
- **Preserves ability for LSE's to structure customized portfolios:** Making this a month-to-month obligation for LSEs gives the marketplace the ability to structure customized portfolios of capacity resources. That is, it is friendly to retail access markets. Likewise, new generating capacity or improvements that result from maintenance can enter the market at virtually any time. Demand side resources that are not particularly amenable to long forward contracting can also enter the marketplace at virtually any time.
- **Ensures that all capacity resources participate in the capacity markets:** Even if bilateral contracts are not the primary vehicle for resource commitment, capacity resources have the assurance that they will be able to participate in the capacity spot market via ERCOT's demand curve auction.
- **Provides more appropriate venue for regulatory involvement in the markets:** Incorporating a demand curve into the planning process provides an appropriate level of intervention by ERCOT and state regulators in the market. Specifically, the regulatory intervention is only imposed in the spot market, just as energy price mitigation occurs in the spot energy markets. As such, it maximizes the potential for buyers and sellers to enter into transactions to procure necessary resources.

ATTACHMENT 3

Organization of Midwest ISO States

Resource Adequacy and Capacity Market Working Group (RAWG)

"DISCUSSION PAPER ON RESOURCE ADEQUACY FOR THE MIDWEST ISO ENERGY MARKETS"

In reviewing the August 3, 2005 "Discussion paper on Resource Adequacy for the Midwest ISO Energy Market (MISO White Paper), it is clear that MISO—unlike some ISOs/RTOs, is resisting taking on the role of a market principal who will correct flaws in spot market design or "manage" price volatility through an organized separate capacity market. That said, it is also apparent that discussion and detail on certain integral or interdependent issues are either deferred elsewhere or are missing from the record. With that observation, the OMS RAWG respectfully submits the following questions:

THE MISO RESOURCE ADEQUACY PLAN – Responsibility Issues

1) Page 3 of the White Paper observes that, "certain State Regulators firmly believe that the states have sole jurisdiction over the resource adequacy construct" and that MISO "will endeavor to implement a construct that satisfies the federal regulatory directives while recognizing the diversity of state regulatory oversight in this area." There may be some states within the MISO footprint that have declined to directly exercise authority in the area of resource adequacy, thereby, effectively, relying on either "the market" or on other entities such as regional reliability councils or RTOs to ensure resource adequacy. While these states may not have made any definitive pronouncements about resource adequacy <u>jurisdiction</u>, they have chosen not to exercise resource adequacy <u>authority</u>. How would MISO's White Paper resource adequacy construct recognize and deal with this kind of state diversity in situations, in particular, where the state is implicitly relying on the RTO, rather than "the market," to ensure resource adequacy?

2. In the "Steps Forward" section of the White Paper, MISO notes that one of the specific characteristics of the Region is "the electrical, political and regulatory diversity of the footprints." (White Paper at 6) How does MISO see the creation of Reliability First RRO as a subregion of NERC (or its successors under the Energy Policy Act of 2005) affecting this "diversity?"

3. A MISO Planning Subcommittee meeting August 11, 2005 Agenda Item 7b presentation, page 12, notes that Rao Konidena is heading up a project to develop LOLE and reserve margin analysis for the ReliabilityFirst RRO. The project will also determine how a reserve margin fits with Module E and SAWG initiatives. In addition, ReliabilityFirst may just require a LOLE of 1 in 10, and let the RTOs determine the reserve margin

   a.) What is MISO's view on who will be responsible for establishing reserve margins, and who will be responsible for enforcing reserve margins in MISO's footprint?

b) What is MISO's view on what MISO's role will be in establishing and enforcing a planning reserve margin?

c) What is MISO's view on what MISO's role will be in establishing and enforcing an operating reserve margin?

THE MISO RESOURCE ADEQUACY PLAN – Operational Issues

4. The White Paper states the Resource Adequacy Plan will provide reliable price signals that will drive investment in generation and transmission assets. It can be argued that resource adequacy requires not only a sufficient aggregate amount of generation capacity, but also different types of capacity in appropriate amounts. A basic economic principle is that markets can allocate resources efficiently only if the markets are complete; i.e. prices are established for all scarce resources. An important consideration in the completeness of MISO markets involves the range of ancillary services to be included in the day-ahead and real-time markets.

a. To what extent does the efficacy of the MISO long term resource proposal depend on the development of efficient markets for operating reserves, regulation, load following, etc.?

b. What lessons can be learned from the experiences in other restructured markets around the world? Has the MISO staff reviewed these experiences?

5. The White Paper states "as a short-term concept capacity (i.e., operating as compared to planning reserves) is an important aspect of reliability." (White Paper at 4)

a) How does MISO account for operating reserves today?

b) How will MISO determine, if at all, that it will have sufficient operating reserves in its footprint when needed as demand changes?

c.) Does MISO envision an ancillary service market? Explain in detail what ways an ancillary service market is a necessary and integral for MISO's White Paper proposal.

d) Will planning reserve margins continue to be an important aspect of reliability?

6. On the August 3rd SAWG/RAWG conference call , RAWG member thought they heard MISO representatives state two positions regarding short-term energy market relationships to capacity. One summary statement was that there should be "no recovery of peaker investment in the real-time energy market." The other statement was more general in regard to not linking other ancillary services or tariffs concerning capacity to the day-ahead market.

a) Why does MISO think that relaxing a Day Ahead cap will produce "iron in the ground" in a bid for next 24 hours?

b) Why does MISO not pay for the "reserve" capacity historically built specifically to support the system with spinning and non-spinning reserve margins (but not energy) at the time MISO relies on those units to provide that service?

7. Loss of Load Expectation and Reserves:

a) Could MISO provide an annual "assessment" of the future systems (5 to 10 years out) of the Loss of Load Expectation (LOLE) for each of the 14 delivery zones and the amount of the capacity deficiency, based on the current generation queue and the planned and/or proposed transmission configuration to meet a 0.1 LOLE?

b) Could this be done in conjunction with PJM to determine an LOLE for a Common Market footprint with cross RTO sales?

8. Reserve Sharing: Today the emergency procedure for an hourly capacity shortage is to have a load shedding based on a pro-rata basis across the footprint and not reserve margin. Why would one not have a transparent capacity/reserve agreement to have capacity installed to meet a 0.1 LOLE in a timeframe of constructability for generation or transmission?

THE MISO RESOURCE ADEQUACY PLAN – Price Signals and Long-term Contract Issues

9. Page 2 of the MISO White Paper asks the rhetorical question of how to "enhance and/or create a forward price signal that will guide or facilitate investment decisions."

a) What evidence does MISO have that the existing market structure generates a price signal that either fails to guide investment decisions or fails to lead market participants to the investment decisions that MISO thinks they ought to be led to?

b) If MISO has a pre-conceived notion about what future investment decisions market participants ought to be led to and designs a resource adequacy construct that leads to those decisions being made, how is that better than MISO performing a centralized role (like in PJM's RPM model) that leads more directly to the same outcome?

10. Page 9, first paragraph following the bullet points reads "…allow it to be a fungible instrument that may be traded many times prior to actual delivery of the energy contracted for under the contract. Specifically, the contract will need to take into account the homogeneity of the good sold under it, the deliverability of such good, and the settlement of such good and possible liquidated damages."

a) Please explain what is meant by "take into account the homogeneity of the good sold"? Please give examples to show what would constitute homogeneity?

b) What is meant by "the deliverability of such good"? Who would be responsible for determining whether the good is deliverable? What process would be used to determine if a particular transaction under a standardized contract is deliverable?

c) It can be argued that it is essential that forward traded contracts be sufficiently forward looking so as to allow new entrants to participate and contest the prices offered by incumbent generators. Given this consideration, does MISO have any idea how forward the standardized forward contracts might need to be?

11. Page 9 states "[w]hile longer term contracts currently exist, they do not provide for a long-term hedge to accompany the transaction contemplated by the contract, therefore limiting transactions under such contracts." The next sentence refers to the need to accompany the longer term contracts with long-term financial transmission rights.

a) Is the only difference between existing longer term contracts and the proposed standardized contract the ability to include long term FTRs, or are there other differences?

b) If there are other differences than just the ability to include long term FTRs, please explain what these differences are?

12. The White Paper mentions in its Conclusion (see page 11) that "[t]his Midwest resource adequacy construct has the flexibility to encompass physical capacity mechanisms like the MAPP construct under its umbrella... ." However, the White Paper neglects to discuss the successfully operating MAPP generating reserve sharing pool while focusing on ICAP and other failed eastern models as reasons for long-term energy contracts.

a) What are the major benefits of long term energy contracts that would make them preferable to common long-term bilateral capacity contracts?

b) Would a bilateral capacity market develop more efficiently if there were an enforced capacity obligation for all Load Serving Entities (LSEs)?

13. Page 9 of the White Paper describes MISO's idea for the development of a standardized forward energy contract.

a) What does MISO think is inadequate about existing standardized contracts being used by market participants today?

b). What problem does MISO believe can be addressed by development of a new standardized forward contract?

c) What would MISO do to induce or force market participants to use the new standardized forward contract?

THE MISO RESOURCE ADEQUACY PLAN –Supporting Infrastructure Issues

14. In the same way that transmission constraints cause energy prices in spot markets to diverge, transmission constraints also cause locational divergence in forward capacity

prices. One of MISO's stated goals in the White Paper is to facilitate private parties' forward bilateral contracting. What changes does MISO plan to make to its long term transmission planning process to address transmission constraints so as to reduce forward locational capacity price divergence and facilitate forward bilateral contracting?

15. Page 7 of the White Paper implies that MISO sees its role in transmission planning only as "advisory." Please describe the extent of the role MISO expects to play with respect to transmission planning in the context of assuring supply adequacy.

16. Would the development of a robust transmission system that reduces system congestion eliminate some of the perceived need to implement long-term FTRs for forward energy contracts?

THE MISO RESOURCE ADEQUACY PLAN – "Free-rider" and Other Cost Issues

17. How will LSEs be prevented from "leaning on the system" at the expense of other customers?

a) To ensure LSE maintain sufficient capacity to meet their load, would MISO consider including a capacity "obligation," a true-up assessment, or devising penalties for "free-ridership? "

b) How would long term energy contracts assure that LSEs maintain adequate capacity to serve their peak loads?

18. The White Paper notes that the Resource Adequacy Plan "should not impose any additional costs for [MISO's] market participant without a commensurate increase in system reliability." (White Paper at 7)

a) How will this guiding principle be accommodated?

b) In the interest of cost effectiveness, how will MISO determine such an "increase" in system reliability before imposing these "additional costs" on market participants?

c) Will this "determination" be verifiable? Independent?

THE MISO RESOURCE ADEQUACY PLAN –Resource Development

19. How will MISO assure that sufficient generation capacity resources are available to serve load as aging plants retire or are unable to keep up with changing demand?

a) What, if any, role does MISO see for itself in supporting the States on a State-by-State basis or from a regional perspective in resource development? For example, to date, MISO has helped the Minnesota Department of Commerce (CAPX Project) and the Michigan Public Service Commission (Capacity Need Forum) with planning as part of state-sponsored initiatives to determine resource adequacy.

b) What role does MISO see itself playing to support resource development?

THE MISO RESOURCE ADEQUACY PLAN – Changes To Be Made?

20. In the section on Energy Plus Operating Reserve Markets, the White Paper suggests that Offer Caps be "relaxed."

a) Explain what MISO means by *relaxed*.

b) If relaxed means raising the cap, explain the process MISO intends to use to effect this change.

c) Would this change go into effect all at once, or be phased in over a time period?

d) Given that one of the justifications for offer caps is lack of demand response, how does MISO expect to demonstrate demand response that is sufficient and of the right type to justify relaxing the caps?

e) What is to be gained by relaxing the bid cap? Remember this is a market clearing price payable by all energy, not just a few MWH on the margin as with previous price spikes. How much more incentive beyond $1,000/MWH is needed?

f) Wouldn't the recovery of capacity related costs through energy markets send inferior price signals compared to recovery through bilateral capacity markets resulting from an enforced capacity obligation?

g.) What does Dr. Patton have to say about relaxing offer caps and the process to use?

21. Page 7 of the White Paper states MISO's position that "the Resource Adequacy Plan should not promote the abuse of market power." It, perhaps, is telling that MISO did not state this as, "the Resource Adequacy Plan should <u>prevent the exercise</u> of market power." Before a relaxation of the energy market offer caps can be found to be just and reasonable, MISO must be able to demonstrate that market power mitigation measures can distinguish between the exercise of market power and market driven scarcity pricing on an ex ante basis.

a) Please elaborate on MISO's plans to prevent the exercise of market power while "relaxing" the energy offer caps.

b) If MISO's plans do not involve the ex ante prevention of market power exercise, please explain how MISO plans to make the victims of market power exercise whole after the exercise of market power.

22. In the section on Energy Plus Operating Reserve Markets, the White Paper suggests that Market Mitigation be *altered*.

a) Explain exactly how MISO expects to distinguish scarcity pricing from market power during situations where prices rise significantly.

b) What does Dr. Patton have to say about altering Market Mitigation and what process should be used in its place?

23. Page 8, paragraph “2) Market Mitigation…altered,” states “Conduct and impact tests can be developed that are tailored specifically based on whether resources are in rate base, have long-term contracts or depend significantly on revenues from the spot markets. Cumulative price thresholds can be developed specifically for each resource.”

a. Does MISO management have specific ideas regarding what the revised market monitoring will look like?

b. When will the specific conduct and impact tests be developed?

c. When will the MISO Market Monitor, Dr. Patton, be asked to present his position on the workability of the MISO resource adequacy proposal, in general, and the revised market monitoring and market mitigation, more specifically?

24. Explain what will happen to Module E during the interim and after MISO’s permanent Resource Adequacy plan goes into effect. Provide dates and how Module E will relate to MISO’s permanent plan.

THE MISO RESOURCE ADEQUACY PLAN – Structural Issues

25. Page 11, Conclusion section, reads “The cost implications and risks associated with this resource adequacy plan are dwarfed by comparison to PJM’s or ISO NE’s proposed capacity market constructs.”

a) Has MISO staff, or anyone else that you know of, done a comparative analysis to thoroughly explore and quantify the cost implications and the risks associated with the MISO resource adequacy plan versus the PJM or ISO NE plans? If yes, please provide the comparative analysis.

b) If no formal analysis has been done by MISO staff or others on which the above statement is based, please explain the basis for this conclusion.

26. Please describe any seams issues that MISO foresees in implementing the energy-only resource adequacy design described in the White Paper should PJM decide to implement a centralized capacity adequacy program like that in RPM. What additional features could be added to MISO’s energy only proposal to address these potential seams issues?

27. Page 6 of the White Paper references the “counterfactual,” (i.e., the most likely alternative). What does MISO see as the list of potential alternatives to its White Paper proposal and which of those does MISO believe is the “counterfactual”?

ATTACHMENT 4

MARKET POWER MITIGATION: PRINCIPLES and PRACTICE

Larry E. Ruff

Charles River Associates

November 14, 2002

MARKET POWER MITIGATION:
PRINCIPLES and PRACTICE

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MARKET POWER MITIGATION: PRINCIPLES and PRACTICE

Larry E. Ruff

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November 14, 2002

1. INTRODUCTION

1.1 CONTEXT AND OBJECTIVES

Consumers and public officials are concerned that suppliers will use market power to drive prices too high, particularly during scarcity conditions when suppliers appear able to charge "whatever the market will bear." Suppliers are concerned that overreactions to such concerns will keep prices so low that existing assets will not recover their costs and future investments in electricity supplies will become unattractive. These opposing concerns both have some justification, and until they are dispelled everybody should be concerned about the reliability and continuity of their electricity supplies.

Current discussions of market power and its mitigation in electricity focus on the spot markets operated by independent transmission providers (ITPs) under the authority of the Federal Energy Regulatory Commission (FERC).[1] In particular, FERC's proposed Standard Market Design (SMD) includes a package of market power mitigation (MPM) measures based on limiting physical withholding and capping suppliers' bids in spot markets, with a resource adequacy or capacity requirement intended to give suppliers additional revenues to offset the lower spot prices. Some version of this general framework, with or without an effective resource requirement/payment, is in use or is being developed for functioning and emerging ITPs, including the Midwest ISO (MISO).

The objective of this paper is to provide an economic perspective on market power and its mitigation in electricity spot markets and to suggest policies that might reduce the concerns outlined above. The focus is on MPM as applied to suppliers, because this is the most important issue in practice. This paper has been commissioned by a group of electricity generating and marketing companies,[2] but the analysis and views are those of the author, an independent expert with extensive experience in the design and operation of competitive

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1 For the purposes here, an ITP is any system operator that uses spot market to manage and price physical operations. Both Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) are ITPs here.

2 These companies are American Electric Power, DTE Energy Trading, Inc., Constellation Power Source, Edison Mission Energy, Mirant, NRG Power Marketing, Inc. and PSEG Energy Resources & Trade, LLC.

electricity markets worldwide. Individual sponsors of this paper do not necessarily share or endorse all the views expressed and recommendations made here.

1.2 Outline and Summary

This paper consists of the four sections below in addition to this introductory section.

Section 2: The Economic Principles and Their Application

This section reviews some elementary economic principles as they apply to spot markets and discusses why and how competitive behavior in a specific market depends on the price-discovery process in that market. It then turns to electricity spot markets in particular, discussing why it is not so easy to know how a competitor "should" behave in an ITP's markets, what happens if spot scarcity prices are suppressed, capacity requirements/payments as alternatives to scarcity pricing, and demand response. The principal theme of this section is that MPM procedures of the type currently being implemented and proposed for ITPs are logically inconsistent and will produce inefficient outcomes unless ITPs use scarcity pricing methods that are more accurate than those currently used or likely to be implemented soon. Until ITPs implement such scarcity pricing methods, MPM procedures should expect and allow competitive suppliers to bid in ways that increase their chances of receiving efficient, market-clearing scarcity prices and recovering their reasonable costs.

Section 3: FERC's Market Power Mitigation Package

The objectives and the four MPM measures in FERC's SMD NOPR are described and analyzed at a general level consistent with the limited details provided by FERC. It is concluded that these measures will, in practice, suppress spot scarcity prices despite FERC's expressed desire not to let this happen. The Resource Adequacy Requirement (RAR) is discussed and shown to require much more thought and development before it can be regarded as a proposal for a workable or effective policy that will offset the effects of suppressed scarcity prices.

Section 4: The MISO Market Power Mitigation Proposal

The MPM proposal currently being considered by MISO is described and analyzed. It is shown that, even with some technical problems fixed, the proposed MPM procedure will result in the suppression of scarcity prices given the way the MISO (and other) spot markets determine such prices. Although some improvements in scarcity pricing that have been suggested for the MISO (and other ISOs) are steps in the right direction and should be encouraged, these are too limited to solve all the problems even if they are effectively implemented. The MPM procedures currently proposed for MISO would suppress scarcity prices and threaten the commercial viability of competitive and needed suppliers. They should be modified to apply less broadly and to allow suppliers to act in ways that will improve their commercial viability.

Section 5: A Suggested Approach to Market Power

The concluding section suggests five central objectives for a successful MPM policy: (1) Market power in spot markets should be put in perspective by focusing on overall market processes and outcomes; (2) spot scarcity pricing in ITP markets should be improved so that MPM can be both less distorting and more effective; (3) until spot pricing is much improved, MPM should be narrowly focused and light-handed; (4) because aggressive MPM procedures will suppress spot prices, as long as such procedures are in place there must effective capacity payment arrangements; and (5) electricity markets should quickly make the transition to full competition, which requires efficient spot scarcity pricing.

2. THE ECONOMICS OF MARKET POWER MITIGATION

This section reviews some basic economic concepts as applied to spot markets and their implications for identifying and mitigating market power in spot markets.

2.1 THE ECONOMICS OF A COMPETITIVE SPOT MARKET

2.1.1 SHORT-RUN AND LONG-RUN MARGINAL COSTS

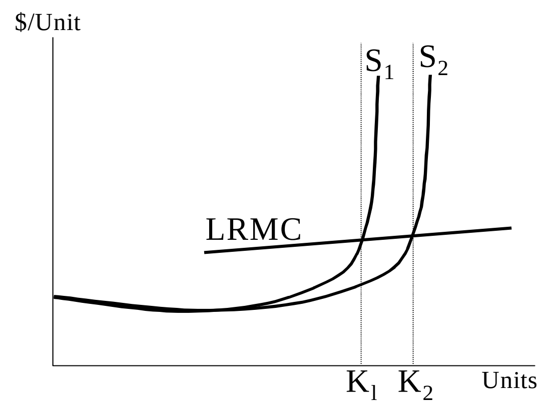
In economic textbooks, a perfectly competitive market is one in which no supplier is large enough to increase the market price by withholding or overpricing some or all of its potential supply. In most real markets, some supplier(s) could increase the market price a little for a while by withholding or overpricing supplies, but any supplier that did so would eventually lose more in profitable sales than it would gain from the higher prices as competitors increased their output to replace the withheld or overpriced supply. A market in which each supplier decides how much to supply at market prices that it cannot profitably affect for long is said to be workably competitive.

A supplier in a workably competitive market maximizes its profits (or minimizes its losses[3]) by selling up to the point where its short-run marginal cost (SRMC) equals the market price but not beyond the point where its SRMC begins to exceed the market price. For deciding how much to produce to maximize profits, a supplier properly considers its SRMC as the increase in present or future costs resulting from increasing output/sales by one (small) unit. A supplier's SRMC is not a single or easy-to-estimate number, but is a sometimes-hard-to-measure variable that depends on the supplier's current and expected future output, current and future (but not past) prices, the existing physical plant and staffing levels, etc.

[3] This qualification is implied but not repeated whenever phrases such as "maximizing profits" are used here. A supplier's maximum profits may be negative – although if they are it cannot stay in business for long and is unlikely to be replaced by another supplier.

Figure 1 illustrates typical SRMC curves for a supplier that produces a commodity using fixed physical assets and variable inputs such as fuel. S_1 is the SRMC curve corresponding to a particular set of fixed assets with a rated capacity of K_1. For output levels below K_1, SRMC is the incremental cost of fuel and raw materials, maintenance and wear-and-tear on equipment, including any opportunity costs if producing more for this market now increases the costs of producing for some other or later market. Over this range, SRMC usually increases slowly with output beyond some point of maximum short-run technical efficiency and then becomes very steep near full capacity K_1.

Figure 1:
Typical SRMC and LRMC Curves



The full capacity K_1 associated with some set of fixed assets can be defined as the steady-state output level at which SRMC is the same as long-run marginal cost (LRMC), defined as the minimum long-run unit cost of producing that output level taking into account all fixed asset costs as well as variable costs given those assets. Because it is always possible to operate above any such measure of full capacity, at least for a while, by paying overtime, sacrificing some technical efficiency, overstressing equipment or delaying maintenance at the risk of earlier or more costly repairs later, etc., the SRMC curve S_1 continues for some distance beyond K_1, becoming infinite where it really is impossible to get anything more from the existing facilities. Given time and money to expand the facilities, the SRMC curve itself can be shifted, as illustrated by the SRMC curve S_2 with higher full capacity K_2 and higher fixed asset costs.

It is critical for the analysis in this paper to understand that the proper or "real" SRMC that a competitive supplier must consider in deciding whether to provide an additional unit of output to the market is more complex than, and may far exceed, simpler and more conventional measures of marginal costs such as average fuel costs and variable operation and maintenance (O&M) costs. This is particularly true when a supplier is operating at or near its full output and may have to take extraordinary and very costly measures to increase output slightly. For clarity in this analysis, the term "SRMC" is used for the proper or complex SRMC and the term "simple MC" is used for simpler, more conventional measures of marginal cost.

Figure 2:
SRMC and "Simple MC" Curves

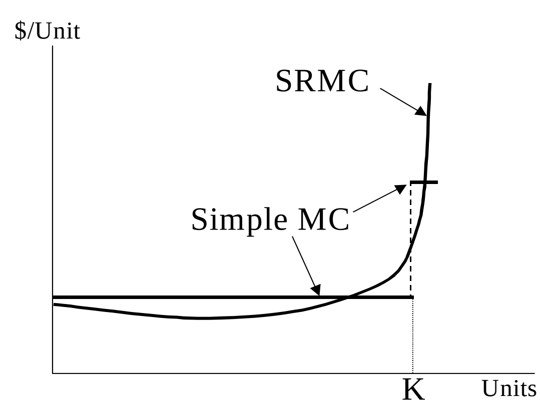
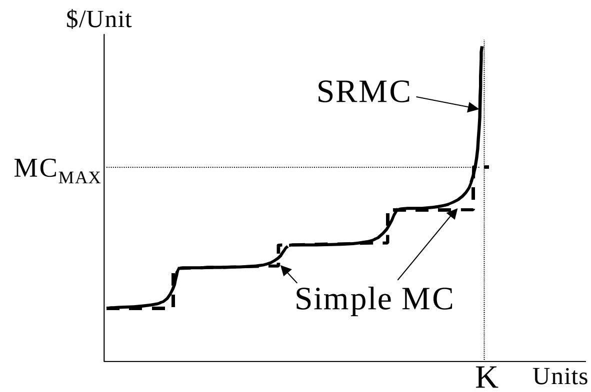


Figure 2 illustrates the difference between a typical supplier's SRMC curve and the type of simple MC often assumed in electricity markets for illustrative purposes and – far more importantly – for operational and pricing purposes. Simple MCs are based on average SRMCs over wide ranges, and do not usually include even the kind of step illustrated in Figure 2, which at least acknowledges that marginal costs become high near maximum output. Even if simple MC is defined to include some such "sculpting" at high output levels, MC for a supplier operating at full capacity is often – but incorrectly – defined as the incremental cost of the last unit produced, not the much higher (or infinite) cost of the next unit that could (or could not) be produced.

Figure 3:
Industry SRMC and Simple MC Curves



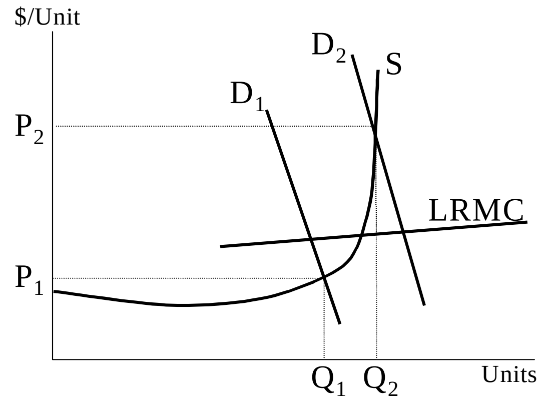
Because each supplier in a workably competitive market will produce up to the point where its own SRMC reaches or begins to exceed the market price, the SRMC curve for an individual facility is also the short-run supply curve for that facility. If all facilities face the same price for their output, the short-run supply curve for the market as a whole is the horizontal aggregation of the individual SRMC curves. Figure 3 illustrates an industry supply curve for an industry in which different suppliers have different SRMCs, and how such a supply curve might be approximated by using the simple MCs of different suppliers. Such simple MC curves are often incorrectly interpreted to mean that, when all suppliers and hence the industry are producing at full capacity, the SRMC of each supplier is the highest step in its simple MC curve and the SRMC of the industry is the highest of these, MC_{MAX} in Figure 3. The more correct interpretation is that the SRMC curve of each supplier and hence of suppliers as a whole becomes vertical at full output.

2.1.2 MARKET-CLEARING PRICES AND PRICE VOLATILITY

A workably competitive market clears where demand equals supply, and the market price at this point will equal the SRMC for suppliers as a whole and for each individual supplier. This is true for a supplier producing at its maximum output because such a supplier can get another unit to sell if, but only if, it buys it at the market price; its SRMC curve at full output is vertical up to the market price, however high that is. The market price and hence the true SRMC of such a supplier may be far above any conventional measure of simple MC. If all suppliers are producing at or near full output the market price and hence all SRMCs can be far above the simple MC of any supplier.

Figure 4 illustrates a market in which suppliers have a fixed set of assets that result in the short-run supply curve S (assumed to remain unchanged over several short-run periods). As demand varies from one short-run period – which may be a year or a week or an hour, depending on the technical characteristics of the commodity – to another, the market equilibrium defined by the intersection of the demand and short-run supply curve will change and the short-run or spot market price will move along the SRMC curve – for example, from P_1 when demand is D_1, to P_2 when demand is D_2. The spot price or SRMC will be above LRMC at some times and below it at other times, but if there are no barriers to entry or exit and the market is approximately in a long-run equilibrium, the average price will be close to LRMC; if it is not, new facilities will be built or existing ones will be shut down until it is.

Figure 4:
Volatility in a Competitive Market



A scarcity[4] or peak period is defined as one in which market demand is high relative to the available supply, as illustrated by demand curve D_2 in Figure 4. At such times the market-clearing spot price can be much higher than it is usually or on average and much higher than LRMC. But the fact that spot prices are higher than LRMC during peak or scarcity periods does not mean they are "too" high during those periods or overall. Prices are too high during scarcity conditions only if a competitive market – one in which the market price is at the intersection of SRMC and demand – would clear at a lower price. Prices are too high overall only if spot prices averaged over a period in which entry is possible are above LRMC.

During scarcity conditions, most suppliers are operating on the steep parts of their supply curves where SRMCs depend on judgmental factors such as risks, and consumers may be taking or considering demand-reduction actions that have uncertain or unusual costs. Under these conditions, the cumulative effect of small and unpredictable changes in the judgments of individual suppliers and/or consumers can shift the supply or demand curves enough to have large effects on competitive scarcity prices. This makes it essentially impossible to forecast the levels of scarcity prices accurately or even to explain those levels after the fact based on easily observable factors that usually define simple MCs, such as fuel costs.

Because competitive scarcity prices can depend on so many complex and even judgmental factors, there is no reliable way to decide when market-determined scarcity prices are too high or to compel suppliers to act so as to produce Goldilocks prices: Not too high, not too low, but juuuust right. Any administrative procedure for controlling prices or market

[4] "Scarcity" is only a relative term. Economically speaking, anything that has a positive price is scarce, meaning that it would be good to have more of it. The term "scarcity price" generally refers to a price created when the demand curve intersects the supply curve on the (near) vertical section close to maximum output. Under these conditions, not only is the commodity itself scarce, but the assets needed to produce the quantity are scarce and are earning "scarcity rents" – the excess of revenue over average SRMCs or simple MCs need to recover fixed costs and encourage additional investment when needed. Real prices always include some scarcity rents for the lowest-cost producers, even in normal or "non-scarcity" periods.

behavior will get it wrong much of the time. And, because any such procedure will target the highest prices that are the hardest to explain objectively or to tolerate politically, such a procedure almost inevitably suppresses scarcity prices below competitive levels.

Forcing spot scarcity prices below competitive market-clearing levels will reduce the efficiency of the market and increase total costs to consumers in the long run. In fact, even if scarcity prices are very high, reducing them may do consumers surprisingly little good, because other prices will eventually have to increase enough to make up for the loss of scarcity rents to suppliers. Given the difficulty of knowing when a spot price is too high, the high costs and risks of trying to reduce it, and the low payoff even if it is done well, it is usually better not to try unless there is clear evidence of harm to the larger market. This is discussed further below in the context of electricity spot markets.

2.1.3 Price-Discovery Processes and Supplier Offers

The logical conclusion that prices in a workably competitive market will tend to equal – more realistically, approximate – the SRMC of each supplier says nothing about the market process that determines the market prices. In particular, it does not say that each competitive supplier always will or should ***offer*** all of its supplies at its own SRMC. Whether or not and at what price a competitive supplier offers to sell anything in the market depend on the specific mechanics of that market.

In real, workably competitive markets for things as disparate as tomatoes and real estate, suppliers make offers by posting the prices at which they are willing to sell. But no seller in such a market decides what offer price to post by looking at its own SRMC curve. Instead, suppliers observe asking or transaction prices in the market yesterday or next door, consider any factors that may make things different today or here, make their best estimate of the market-clearing price here today, and then offer to sell at that price. A supplier may decide to offer more or less (or nothing) based on its estimate of the market-clearing price and its own SRMC curve, but its offer price is based on its estimate of the market-clearing price, not on its average SRMC much less on any simple MC.

Furthermore, because a supplier in such a market will ultimately sell at or near its own offer price, each supplier's offer price must frequently be above its average SRMC if it is to recover sufficient fixed costs to stay in business. Nobody expects a farmer to offer tomatoes at the cost of picking them and driving them to market, or a homeowner to offer its house at the cost of sprucing it up for sale. In most markets, no supplier is expected to offer to sell everything – or anything – at its own simple MC or is accused of trying to exercise market power if it does not.

The behavior of competitive suppliers expected in most real-world competitive markets described above is much different than what is usually expected in electricity spot markets. There is a widespread, but unexamined and often incorrect assumption that a competitive supplier in an ITP's spot market would always offer all its output at some average SRMC or simple MC, from which it seems to follow that the way to control or mitigate suppliers' market power is simply to require all suppliers to offer all their supplies at or near their simple MCs. What is the basis for this assumption and what are implications if that assumption is incorrect?

The proposition that a competitive supplier in an ITP's spot market would offer all it available output at its own simple MC is dependent on two critical assumptions: (1) that the supplier is allowed to submit sculpted bids so that its simple MC can become very high at high output levels to reflect its actual SRMC at those levels; and (2) that the ITP's pricing process will determine efficient, market-clearing prices that do not necessarily depend on, and may be much higher than, any supplier's bids. In particular, when demand is high relative to available supply, the ITP must base market prices, not on estimates of each supplier's average SRMC over its full output range, but on sculpted supplier bids that may become very high at high output levels, and/or on demand bids, import/export bids, and even on the implicit costs of such things as demand interruptions, low operating reserves or risky system operations. As discussed in sections 2.2.1 and 2.2.2 below, in theory ITP spot markets should operate this way but in practice they do not. And if they do not, there is no logical or practical reason to expect or to require suppliers in those market to operate as though they did. The implications of this commonsense observation are discussed further below.

2.2 The Economics of an Electricity Spot Market

Standard economic principles apply to electricity spot markets, but require some special twists and implications due to the physical and economic peculiarities of electricity.

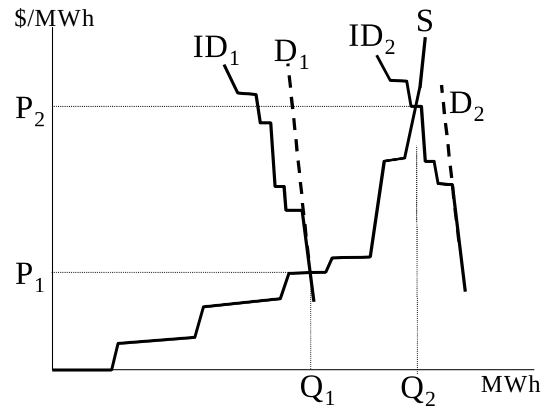
2.2.1 ITP Spot Pricing in Theory

In the "normal" market processes discussed above, a rational, competitive supplier bases its offer price on the expected market-clearing price, not at its own SRMC, and then offers to sell at that price the amount that maximizes its profits at that price. But an electricity system is so dynamic and complex that operations would be unnecessarily costly and even unreliable if each supplier had to estimate market-clearing prices and then offer to sell its profit-maximizing quantity at those prices without regard to what actually happens in real time. That is why an electricity market needs a central market-clearing and pricing process operated by an ITP.

The fundamental concept underlying ITP-operated energy spot markets is that all market participants should submit bids revealing the costs to suppliers of producing energy and the value to consumers of consuming it, and the ITP will use this information and everything else it knows about the system to determine spot prices that equal/approximate the real SRMC of meeting demand reliably at each time and place. In particular, under scarcity conditions when very costly actions are necessary to meet demand reliably, the market-clearing prices may be independent of and much higher than the bid prices of any suppliers. If an ITP spot market applies these concepts correctly, a workably competitive supplier will submit a bid curve with different prices at different quantities, in effect creating a simple MC curve that approximates its true SRMC curve, because this will result in the supplier selling the amounts that maximize its profits at the market prices, whatever these prices turn out to be. But it will do this only if it knows that the ITP will, if market conditions so indicate, determine a market-clearing price that is higher than even the highest step in its bid curve.[5]

The theoretical model of ITP spot pricing underlying the usual assumption about supplier bidding is illustrated in Figure 5. In theory, suppliers operating in the market submit to the ITP, not simple MC bids based on fuel costs, variable O&M, etc., but "sculpted" bids reflecting their true SRMCs, including the very high and sometimes judgmental SRMCs associated with operating near and beyond some measure of maximum output. The ITP uses these bids from "in-market" suppliers to construct a supply curve S, which will have many small steps increasing to very high levels near and beyond the full capacity of all suppliers.

Figure 5:
ISO Spot Pricing in Theory



The ITP also uses demand forecasts, estimates of demand elasticities and explicit demand bids[6] to construct a market demand curve for each period, illustrated by D_1 and D_2 in Figure 5. But the ITP knows that, if there is not enough supply to meet demand, it will not disconnect consumers as a first response. It will do many other things, such as buying imports from neighboring ITPs, canceling scheduled exports, calling interruptible load contracts, taking energy from reserves, overloading transmission facilities, letting frequency or voltage drop, and as a last resort curtailing some "firm" demand if necessary to keep the system from collapsing. Call these "out-of-market" or "OOM" actions, because that is how they are usually treated, even though the objective should be to get them into the market.

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[5] The discussion here is dealing only with the energy spot markets, but even in concept an ITP needs more than these to operate the system reliably. For one thing, reliability services such as operating reserves, voltage support or reactive energy, frequency control or regulation, etc., are not adequately managed or compensated in energy markets, so the ITP must acquire and pay for these in ancillary service markets. But even within the energy market itself, there can be situations where SRMC-based energy prices will not support energy suppliers that are needed for reliability purposes; in a typical example, a combustion turbine (CT) may be needed at some particular constrained location but runs at its full output so seldom that prices in energy and ancillary service markets will not cover its full costs. Such cases require special arrangements, such as a reliability-must-run (RMR) contract between the ITP and the CT. If the CT must support itself from energy market revenues it must be allowed to act in the energy market to produce prices that will cover its costs with a fair return.

[6] A demand bid should be an offer to reduce energy purchases if the price increases above some level, not an offer to reduce energy purchases if paid to do so. Anybody should be free to sell back energy it does not consume if it has bought it (e.g.) in a forward market, but nobody should be paid for something it might have bought but didn't.

In theory, the ITP should estimate the costs of the various OOM actions it may take and then put these actions and their costs into its dispatch, market-clearing and pricing engines along with in-market supply and market demand. OOM actions could be treated as additions to supply for this purpose, but if they are treated as reductions in demand the ITP's total demand for in-market energy – ID_1 and ID_2 in Figure 5 – should have significant elasticity at high prices. When demand is low, as represented by ID_1, the market will clear at a low price P_1 with little or no demand response and no OOM actions. But when market demand is higher than in-market supply, as represented by ID_2, the ITP will have to move up the in-market supply and OOM-adjusted demand curves to clear the market at a very high price, P_2 in Figure 5, that is set by either an OOM action or a sculpted supplier bid.

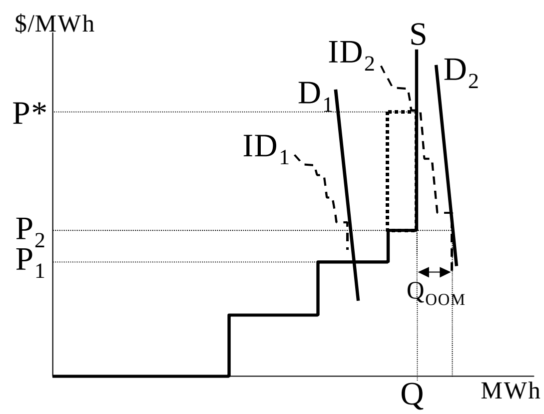
If the ITP's dispatch and pricing process worked as the above theory says it should, competitive suppliers would submit sculpted bids to the ITP approximating their individual SRMCs. But suppliers would do so only because they would know that the ITP would use these sculpted SRMC bids, plus the bids or implicit costs of market-driven demand reductions and OOM actions, to determine efficient, market-clearing prices. In particular, under scarcity conditions the ITP would base the market price either on sculpted supplier bids that become very, even arbitrarily, high for the last few MWh offered, or on the bid or deemed costs of demand reductions and OOM actions that can be higher than any supplier bid prices. If the ITP does not live up to its side of the bargain and reliably determine scarcity prices based on this concept, there is no reason to expect or to compel competitive suppliers to ignore this reality and to continue bidding as though the ITP were doing what it is not doing.

2.2.2 ITP Scarcity Pricing in Practice

In practice, ITP spot markets do not operate as the above theory says they should. In fact, ITP pricing software usually mechanically calculates market prices from the offer prices of on-system generators even when the ITP must use demand reductions, imports, energy from reserves and even higher-cost OOM actions to clear the market, and even when it must use emergency actions to keep the system from collapsing.

Figure 6 illustrates an ITP dispatch and spot pricing process that more closely resembles current practices than the theoretical process illustrated in Figure 5. In this process, the ITP constructs a supply curve S using bids from suppliers, but now expects or requires these bids to be relatively simple, with no more than a few large steps at levels reflecting fuel and variable O&M costs and at most some "reasonable" allowance for risks and opportunity costs. The ITP also creates a market demand for each period, D_1 and D_2 in Figure 6, perhaps reflecting some price elasticity and/or demand bids. The ITP also has a set of OOM actions it will take if

Figure 6:
ISO Spot Pricing in Practice



necessary to keep the lights on, but regards these as truly out-of-market actions in the sense that their actual or deemed costs will not be used in computing market prices. The ITP will presumably have in mind some implicit demand curve for in-market energy indicating the order in which it will take the OOM actions if necessary and the implicit costs of doing so – ID_1 and ID_2 in Figure 6 – but does not use these for pricing purposes.

When market demand is D_1 in Figure 6, the ITP dispatches the supply curve S to meet demand at the market-clearing price P_1 with no need for the OOM actions represented by the ITP demand curve ID_1. But when market demand is D_2, there is not enough in-market supply to meet market demand, so the ITP must use the OOM actions represented by the ITP demand curve ID_2. When the ITP has dispatched Q_{OOM} of OOM energy to close the gap, the implicit – and correct – market-clearing price is P*. But the price-determination process ignores the OOM actions and sets the market price at P_2, the highest in-market supply bid taken.

This ITP market-clearing pricing process is very different than the theoretical one described in the preceding section – the one that would motivate competitive suppliers to offer all their energy at sculpted bid prices approximating their individual SRMCs. In fact, this ITP market process is much more like the processes in most other markets, in which suppliers will not get the market-clearing price unless they estimate it themselves and then offer to sell only at that price. In particular, if all suppliers offered all their energy at their simple MCs, none of them would get the market-clearing price under scarcity conditions and some of them would soon be out of business.[7]

So how would competitive suppliers, if unconstrained by such things as market mitigation procedures, conduct themselves in the market given this ITP price-formation process? The textbook concept of "perfect" competition is not helpful here,[8] but examples from real workably competitive markets are. When sellers of tomatoes or houses know they will not get the competitive market-clearing price unless they ask for it, they estimate it and ask for it. It is reasonable to conclude, therefore, that when an ITP market will set the market price below market-clearing levels unless at least some suppliers bid at the market-clearing price, some suppliers will estimate the market-clearing price and bid at that level, even if the market is highly competitive. For competitive suppliers to do otherwise – to offer all their supplies at some estimate of their individual simple MCs knowing that the ITP's software will use such offers to compute and pay them a price that is much less than the real market-clearing price – would be irrational and even commercially suicidal.

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[7] More accurately, those "peakers" who make most of their money from scarcity prices would go out of business unless they could qualify for the ITP's OOM payments or capacity payments. "Baseload" suppliers who can make money at normal times would survive, but only if they received higher average prices in normal times and/or capacity payments.

[8] In the textbook definition, a "perfect" competitor does not make a price offer, but passively observes the market price and then sells as much or as little as it chooses at that price. In any real market, suppliers must make pricing decisions that will affect what they are paid.

This reasoning leads directly to the conclusion that, in an ITP market that uses the kind of scarcity pricing process illustrated in Figure 6, workably competitive suppliers would not all offer all their supplies at simple MCs approximating their individual SRMCs. At least some of these suppliers would – and should, if the objective is to produce reasonable scarcity prices – offer some significant amount of their output at levels reflecting their estimate of market-clearing prices. In Figure 6, for example, if the marginal generator with SRMC of P_2 increases its bid price to P* the ITP will set the market price at P* and all generators will get the efficient, competitive, market-clearing price. In fact, there is no other way for such a market to produce competitive scarcity prices.

An electricity market that requires suppliers to predict and bid the market-clearing prices – a so-called pay-as-bid market – can be inefficient under normal conditions, because suppliers will not be able to predict market clearing prices accurately and errors in their individual predictions will result in inefficient dispatch and operations. During scarcity conditions, however, essentially all suppliers will be running at or near full capacity, so such dispatch inefficiencies are less likely to be important, particularly if it is the highest-cost suppliers who are bidding at their estimates of the market-clearing price.

If an ITP market will not produce market-clearing scarcity prices unless some suppliers bid such prices, competitive suppliers should be expected, allowed and even encouraged to do what unconstrained competitive suppliers would do: bid at their estimates of market-clearing prices even if this means bidding well above some estimate of their simple MCs. Such bidding conduct should not be regarded as an exercise of market power just because it increases prices up to competitive levels, as long as it does not push prices higher than competitive levels. And a market in which suppliers can, do and must behave this way in order to get market-clearing scarcity prices should be regarded as workably competitive as long as such behavior does not result in average prices above competitive levels.

The main problem with these suggested definitions of the exercise of market power and a workably competitive market is that they require difficult and contentious judgments about what competitive prices really are. But this is just as true of the approach to MPM currently favored by ITPs and FERC, which implicitly assumes that it is easy to determine the competitive market price in an ITP market: simply plug some estimate of suppliers' simple MCs into the ITP's pricing engine and turn the crank. As discussed in the next section, there is no logical basis for this assumption given the way ITPs currently determine scarcity prices.

The most relevant measure of spot market prices for judging when a market is workably competitive at some location is not the spot price during a few scarcity hours, but the average spot price over some period such as a year. If such average spot prices in some region are above estimated supplier LRMCs when there is no shortage of supply, there is good reason to investigate to see if supplier market power – as opposed, for example, to unusually high local LRMCs – is the problem and if it is to do something about it. But if average spot prices are below LRMCs, particularly when there is no capacity surplus, the conclusion should be just the opposite: the interaction of the ITP's computer and suppliers' bidding conduct is keeping prices too low. Indeed, if a MPM procedure discovers that supplier bidding is significantly increasing prices during scarcity periods, and yet average prices are below LRMCs, it is merely demonstrating how inadequate the ITP's scarcity pricing really is and why bids and prices should not be mitigated further.

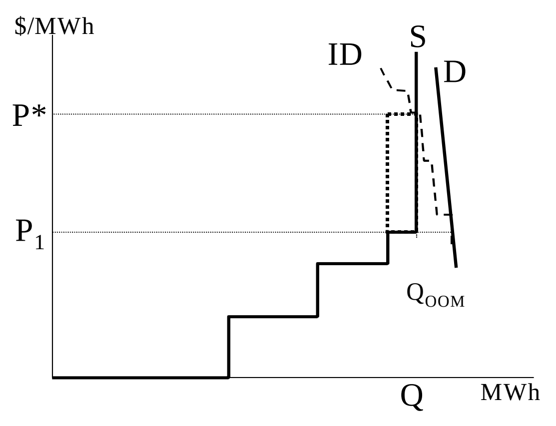
If spot prices averaged over (say) a year are higher than locally relevant LRMCs, or if some suppliers are consistently bidding at levels above any plausible estimate of true market-clearing prices, it may be necessary to do something to mitigate market power. Even here, however, the best solution may be to stimulate additional supply or to negotiate contracts between the ITP and local suppliers, not to try to control prices or even bidding behavior directly. Even if it is decided to control bidding behavior, suppliers should not be required to bid at some low estimate of their simple MCs that will be used in the ITP's pricing process to keep prices below market-clearing levels during scarcity conditions. Something more flexible is required.

2.2.3 The Logical Inconsistency in Automated MPM Procedures

Concerns about supplier market power in spot markets, particularly during scarcity conditions when unconstrained suppliers seem able to drive prices to arbitrarily high levels, have led to the development of automated MPM procedures (AMPs). The basic, if unstated, assumption behind these procedures is that it is easy to know how truly competitive suppliers would conduct themselves – they would all bid at some easy-to-determine estimate of their individual simple MCs – and to know what the resulting competitive spot prices would be – whatever comes out of the ITP's pricing engine when simple MCs are plugged in. Given this assumption, it is perhaps reasonable to say that any supplier conduct that departs significantly from the assumed competitive conduct and that causes a significant increase in the ITP-computed price is a successful exercise of market power, and as such should be prohibited or mitigated. Unfortunately for those looking for a simple solution to the problem of market power, this approach involves a fundamental logical inconsistency.

Figure 7 illustrates a scarcity situation in which market demand is D, the ITP's demand for in-market energy is ID, and the highest simple MC of any in-market supplier – call it a "peaker" – is P_1. An ITP's Independent Market Monitor (IMM) using a typical AMP procedure will set the peaker's reference bid price at P_1, on the assumption that this is what a workably competitive peaker would bid. But this assumption about the behavior of a competitive peaker is valid only if the peaker knows that the ITP will set the market price at the market-clearing level P* even if the peaker bids all its energy at price P_1. If the ITP's market does not use such a scarcity pricing process but instead responds to a peaker bid of P_1 by setting the price at P_1 and meeting demand with OOM energy, there is no reason to expect the peaker to bid P_1; in this case, the peaker would – indeed must, as a matter of commercial survival – bid well above P_1 under scarcity conditions. If the market is workably competitive in the sense that no supplier can profit much for long by increasing prices above competitive levels, the peaker would bid up to but not much beyond P*.

Figure 7: The Logical Flaw in AMP Procedures



An AMP procedure does not ask how workable competitive suppliers would bid given the actual ITP pricing process, but sets the peaker's reference price at P_1 because this is what the peaker would bid in the theoretical ITP pricing process. The AMP procedure then monitors the conduct of the peaker in the real market in which a competitive but rational peaker will bid at P* because that is what it must do to get the market-clearing price. If P* exceeds P_1 by more than some significant but arbitrary amount such as $100/MWh, the AMP procedure will view this bid as a violation of the peaker's conduct threshold and will then test whether the increase in the peaker's bid from P_1 to P* would increase the market price significantly. If the impact test were applied using the theoretical ITP pricing process it would find no market impact, because good ITP scarcity pricing would result in a scarcity price of P* whether the peaker bid P_1 or P*. But the AMP procedure tests for market impact using the real ITP pricing process that sets the market price at the peaker's bid and hence finds that the peakers bid has a significant impact on the market price. So the AMP procedure mitigates the peaker's bid down to P_1, the ITP sets the market price at P_1, and all suppliers are paid less than the market-clearing price they would have received if the ITP really did set scarcity prices the way the AMP procedure assumed when it set reference prices.

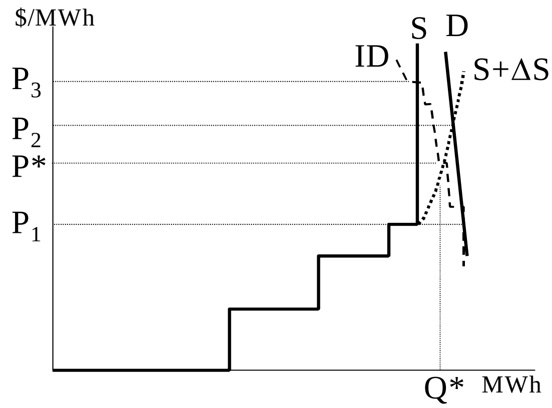
Setting reference bids on the assumption that the ITP uses good scarcity pricing and then mitigating bids to those reference levels even though the ITP does not use good scarcity pricing is logically inconsistent and has the practical effect of virtually guaranteeing that scarcity prices will be suppressed. The best way to fix this logical problem and the serious market distortions it creates is to require ITPs to implement much better scarcity pricing as discussed in the next section, and to allow suppliers to bid in ways that will produce scarcity prices near real market-clearing levels as long as that that is the only way to get such prices. This may be more difficult than simply applying mechanical but illogical AMP procedures, but – as in the old joke about the drunk looking for his keys under the street light – at least offers some hope of finding what market designers and regulators should be looking for.

2.2.4 IMPROVING ITP SCARCITY PRICING

Part of the solution to the problem of getting reasonable scarcity pricing must be to allow real suppliers to bid the way even "perfectly" competitive suppliers would bid in a centralized market-clearing process: by sculpting their bids to reflect the fact that the SRMCs of incremental supplies become very high near and beyond the rated full capacity of a generating unit. Such incremental sculpting does not require a supplier to guess the market-clearing price and then offer significant quantities at that price – a practice that is hard to distinguish from economic withholding – but only to come up with plausible estimates of its own SRMC for the last few percent of its available capacity. Such sculpted SRMC bids, perhaps subject to guidelines defining the quantities that can be offered at prices far above easy-to-estimate variable costs, could produce reasonable scarcity prices even if the ITP uses only supply bids to determine prices.

It is not easy to know just how fast and how far SRMC increases near and beyond "maximum" output, because this depends on judgmental factors such as the effects of stressing equipment and personnel, the value tomorrow of fuel or reservoir water not used or a boiler tube not replaced today, etc. Under normal, non-scarcity conditions it may not be worth worrying about such things, so the last increments of output may simply not be offered, or may be offered but not delivered if dispatched at a too-low price. But when scarcity conditions are likely, suppliers should be allowed, even encouraged, to submit sculpted bids reflecting their judgments about how their SRMCs increase at high output levels and these judgments should not be second-guessed as long as they are within specified guidelines.

Figure 8: Sculpted SRMC Supplier Bidding



For example, a generator with a nameplate capacity of 100 MW might offer 95 MW at its average fuel and variable operating costs of $30/MWh, but offer the next 5 MW at its full average cost or LRMC of (say) $100/MWh and each of an additional 5 MW as emergency energy at increasing prices reaching some high bid cap such as $5,000/MWh. Only the lower prices in such a sculpted bid could be easily related to objective measures of cost, but the higher prices for incremental output, while judgmental, are probably closer to real SRMCs than some simple measure of fuel costs would be. And offering incremental output at very high prices is better than not offering it at all – i.e., offering it at a price of infinity – which is usually the realistic alternative.[9]

Figure 8 illustrates how an ITP market could clear with sculpted supply bids. In addition to the in-market supply curve S representing the supplies available at "normal" supplier SRMCs, there would an incremental supply curve ΔS representing incremental amounts offered at higher prices. If the ITP used such sculpted supplier bids in the natural way, under normal conditions little or nothing would change, because the market would clear at low prices with no need for the ΔS supplies. But under scarcity conditions, as represented by the demand curve D, the ΔS supplies would be used and, if there was no other response, would set the price at P_2.

Even if suppliers are providing sculpted in-market supply bids the ITP should still use demand bids and/or OOM actions when these are cheaper. The ITP should create its demand curve for in-market energy, ID in Figure 8, call the indicated actions when they are in merit – and then set the market price at the bid or implicit cost of the marginal supply, demand reduction or OOM action taken. In Figure 8, if the ITP used OOM actions without sculpted

[9] Some generators, particularly combustion turbines (CTs), have little flexibility in operations but are essentially either on or off. This creates serious logical and practical problems for the ITP's dispatch and pricing process and hence for the owners of CTs. For example, when a CT comes on some other generator with lower SRMC may have to reduce its output; in such situations there is no simple definition of the system's SRMC or the market-clearing price. Special pricing and payment rules must be created to deal with such situations. These are very important, particularly for owners of CTs, but are beyond the scope of this paper.

supplier bidding, the market-clearing price would be P_3; if it used sculpted supply bids without taking OOM actions the market-clearing price would be P_2; but if it did both the market-clearing price would be P*, which is necessarily less (or at least no greater) than either P_2 or P_3.

One of the principal advantages of allowing sculpted bidding by suppliers is that it would stimulate the ITP to look for lower-cost ways to clear the market, i.e., to develop a demand curve for in-market supplier energy that is more elastic. Of course, the ITP could allow high-priced bids for incremental or emergency supplies but then treat these as OOM energy that cannot set the market price; this would give the ITP more OOM options and hence would make the actual dispatch more efficient and reliable, but would do little to improve the efficiency of market pricing.

Letting sculpted SRMC bids from suppliers set prices under scarcity conditions is conceptually no different than letting demand bids from consumers or LSEs set prices – everybody's favorite solution to the scarcity pricing problem. If and when demand bidding is used to set scarcity prices, consumers will not be expected to have objective justifications for the specific prices at which they will turn off air conditioners, shut down industrial processes or run back-up generators; it is understood that these price levels are based on complex and often subjective judgments about costs, benefits and risks. In principle, suppliers should have much the same freedom when it comes to offering incremental supplies near and beyond full capacity, although in practice concern about supplier market power may require limits on how much sculpting is allowed.

2.2.5 The Effects of Suppressing Scarcity Prices

Suppressing scarcity prices below competitive, market-clearing levels does consumers no good and even harms them in a long-run, expected-value sense, because demand and supply must be matched somehow and all the non-market ways of doing so are more costly than letting the market work. In fact, even if prices during scarcity periods are somewhat too high, reducing them to just "the right" levels will do consumers little good in the long run as long as entry or the threat of it will keep average spot prices close to LRMCs. Given the impossibility of knowing when and by how much scarcity prices are too high and the low pay-off and high risks involved in trying to reduce them just enough, it is probably better not to try unless there is clear evidence that average prices are materially too high.

If scarcity prices are kept below competitive market clearing levels, the ITP has two basic options for matching supply to demand during scarcity periods: (1) close the supply-demand gap with OOM actions that do not set spot market prices and recover its costs with an uplift or tax on all consumers; or (2) compel or subsidize excess capacity so that spot markets will clear at lower prices, recognizing that the costs of this excess capacity will ultimately be paid by consumers. The capacity requirement/payment option is discussed in section 2.2.7 below. The option of subsidizing OOM energy in the spot market is discussed here.

If there are no significant barriers to entry into or exit from generation – and no capacity payments, as assumed throughout this section – in a long-run, expected value sense average spot scarcity prices must equal the LRMC of peakers and the time-average of scarcity and normal (i.e., non-scarcity) prices must equal the LRMC of non-peakers.[10] Notice that spot prices averaged over the relevant time periods must equal suppliers' LRMCs, not their average SRMCs or simple MCs. In theory, a proper ITP pricing process will produce LRMC-level prices when there is an optimal amount and mix of capacity, because sculpted bidding, demand bids, OOM actions, etc., will be used to set scarcity prices above suppliers' bids.

If an electricity system begins with a reasonably economical amount and mix of supply resources but the ITP's pricing process does not produce efficient and compensatory scarcity prices, all suppliers, not just peakers, will lose money and will stop maintaining or adding supply. Scarcity will increase until eventually even flawed ITP processes will produce more energy, ancillary service and OOM revenues for the remaining suppliers. Total costs will be higher and reliability may suffer because prices are so distorted, but unless the electricity sector is allowed to disappear or is subsidized, in the long run consumers' total bills will have to cover total costs.[11]

If the ITP uses OOM actions to keep spot prices below market-clearing levels during scarcity periods, the reduction in spot scarcity prices will be less than the uplift needed to pay for OOM actions and consumers will be better off during scarcity periods, at least in the short run. Peakers will not be commercially viable based on market revenues, so they will either become OOM suppliers or be replaced by OOM actions (perhaps including load interruptions). Non-peakers are not getting OOM payments but in the long run must still cover their total costs, so prices in non-scarcity periods must be high enough to make ***average*** spot prices equal the LRMC of non-peakers – just as they would be if the ITP were not suppressing scarcity prices. In a long run, expected value sense, suppressing spot scarcity prices by subsidizing OOM energy during scarcity periods leaves average (wholesale) prices essentially unchanged and requires an uplift or tax on consumers; on balance, consumers are worse off.

Even if market power during scarcity periods is consistently pushing spot prices during such periods too high – i.e., above the LRMC of peakers – the benefit to consumers of reducing the too-high scarcity prices is small as long as entry by non-peakers can be counted on to keep ***average*** prices near the LRMC of non-peakers. Reducing prices during scarcity periods to the LRMC of peakers will reduce the margins of non-peakers and make investment in

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[10] A peaker here is any generator whose SRMC and even simple MC is so high that it earns net revenue or operating profits from energy sales only during scarcity periods, although it may earn significant amounts by selling ancillary services and reserves at other times. A non-peaker is any generator that earns significant net revenue or operating profits – or scarcity rents – outside scarcity periods.

[11] Whether the electricity sector just has costs that are a little too high or experiences massive supplier bankruptcies during the transition and on-going reliability problems depends on how bad the ITP's pricing processes are. If an ITP market works too badly it will presumably be fixed – or the whole idea of competitive electricity markets will be scrapped – before the whole system declines into some "long-run equilibrium" with high costs and poor reliability.

them unprofitable or even force some of them to shut down. As demand grows, non-peakers will not be built until increasing scarcity during non-peak periods brings higher-cost suppliers to the margin more often and pushes time-average prices back to the LRMC of non-peakers. During the transition consumers may see lower average prices for awhile and suppliers will have financial problems, but in the long run average prices will be right back where they were before scarcity prices were reduced.[12]

Given all this, and the difficulties of finding and maintaining Goldilocks prices, an aggressive policy of capping or mitigating spot prices whenever market power is suspected can easily do more harm than good. Unless average spot prices are staying above LRMCs even when new supply is not needed, and particularly if average spot prices are below LRMCs when new supply is needed – as seems to be the case in ITP markets these days – suppliers are not benefiting from any exercise of market power and consumers would not gain in the long run from any mitigation of supplier behavior. If MPM procedures discover that some suppliers sometimes bid above their simple MCs and that doing so increases some scarcity prices, this demonstrates only that such bidding is necessary to get prices to competitive market-clearing levels given the way the ITP market actually operates. There is no reason to mitigate such bidding behavior in a real ITP market just because such behavior in a theoretically perfect ITP market might – or might not – be an exercise of market power.

2.2.6 The Problem of Load Pockets

The analysis above concludes that, where there are no significant barriers to entry, it is probably better to err on the side of under-mitigating occasional high spot prices than to create an aggressive MPM program with its associated costs, uncertainties, distortions and probably suppressed scarcity prices. But in a transmission-constrained load pocket there may – or may not – be barriers to entry so there may – or may not – be better reasons to worry about and to mitigate the exercise of market power.

A load pocket is defined here as an electrical area within which (or perhaps a single node at which) prices are or could be higher than they are outside the load pocket because of transmission congestion.[13] The mere existence of a load pocket does not mean that market power within the load pocket is necessarily a problem or should be mitigated, because there may be adequate competition within the load pocket to keep spot prices at competitive levels – even if those competitive spot prices are unusually high during constrained periods or even on average over time.

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[12] The rebalancing of prices may yield some efficiency gains. For example, lowering scarcity prices to suppliers' SRMCs will allow incremental supply to replace more-costly demand reductions during scarcity periods, and increasing non-scarcity prices may prevent some waste of energy during non-scarcity periods.

[13] A load pocket is sometimes defined as an area within which there is or is likely to be market power when transmission constraints are binding. The definition used here is more general and is used to stress the fact that things other than market power that can cause high local prices.

If there are no significant barriers to new suppliers entering a particular load pocket, there is no more reason to worry about market power or its mitigation in occasional scarcity periods here than anywhere else. Even if suppliers within the load pocket could somehow keep prices "too high" during constrained periods indefinitely, entry or the threat of it would drive prices in unconstrained periods down until time-average prices equaled LRMCs. In this case there would be some efficiency losses because prices were too high during constrained periods and too low in other periods, but these costs would probably be less than the costs of an aggressive MPM procedure – particularly given that such a procedure may create the very disincentives to entry that should be eliminated so that prices can adjust to competitive levels in the long run.

If it is unusually expensive to build generation within a load pocket because of fuel supply, siting or environmental problems, LRMCs are higher in the load pocket than elsewhere and hence average market prices and SRMCs should be higher, at least until constraints on transmission, fuel, sites or environmental impact are relieved. There may be many, fiercely competing suppliers in and free entry of electricity suppliers into the load pocket, and yet average spot prices may stay above the full cost of new supplies elsewhere or even above the apparent cost of new supplies in the load pocket for a long time. But it is the scarcity of sites, permits, etc., not supplier market power, that is to blame, and the only real solution is to increase the supply of these scarce assets. If existing suppliers in such a situation appear to be making "too much" money without attracting entry, it is because their excess profits are more properly regarded as scarcity rents on the sites, fuel sources or environmental permits they own, not because they are exercising market power in the spot market.

When it comes to spot pricing, a load pocket is just like anywhere else except that scarcity prices arise more frequently and perhaps rise to higher levels. The best way to get reasonable scarcity prices in a load pocket or anywhere else is for the ITP to allow sculpted supplier bids, price-responsive demand and the deemed bids of OOM actions to set market prices, as outlined above. Until such ITP scarcity pricing is working effectively, suppliers should be expected and allowed to bid some quantities at their estimates of scarcity prices within some limits, even when this is well above their simple MCs, because that is the only mechanism the market has for getting reasonable scarcity prices. Bidding to get prices to competitive levels is not an exercise of market power or a sign the market is not workably competitive unless average spot prices remain above LRMCs when more capacity is not needed.

The only situation in which a load pocket creates serious potential market power problems is where there are only a few independent suppliers within a load pocket, or a single supplier at a node, and entry is difficult because the local market is just not big enough there to support more competitors. In such situations the incumbent supplier(s) may be able to set local prices much of the time and, indeed, may have to bid well above their own simple MCs much of the time just to make enough money to cover their costs. Even here, however, the best solution is to negotiate or impose contracts that assure the needed supplier(s) that they will cover their costs and that remove the incentives to create or maintain artificial scarcity, not to try to keep spot prices from reflecting actual scarcity.

2.2.7 CAPACITY PAYMENTS AS SUBSTITUTES FOR HIGH SCARCITY PRICES

Despite the economic arguments for letting, indeed assuring that, spot prices rise to market-clearing levels even when these levels are very high, doing so is difficult both technically and politically. As a result, most ITP markets in the United States[14] use some form of installed capacity/capability (ICAP) requirement to try to reduce reliance on spot prices, particularly during scarcity periods. FERC's SMD NOPR proposes, as one of its mandatory MPM measures, a resource adequacy requirement (RAR) that, in effect, tries to find a "third way" between reliance on spot scarcity pricing and ICAP-like mechanisms. FERC's RAR proposal is discussed in detail in section 3.2.3 below. This section discusses the basic options for and implications of any such mechanism.

The basic mechanism of any resource[15] payment mechanism is a requirement that somebody – usually LSEs in the U.S. context – contract with or otherwise pay enough resources to meet peak demand plus some reserve margin. If such a requirement is effective, resources will receive resource payments in addition to payments for energy and ancillary services in spot markets. These additional payments will stimulate more resources to be available than would otherwise be there – in effect, shifting the SRMC curve outward along the LRMC curve in Figures 1 and 2 – and hence spot prices will be lower, especially at times of scarcity. Unless the resource payments and resulting excess capacity are very large, scarcity pricing will still be needed at times and hence the ITP should develop some version of the scarcity pricing process outlined above. But the market should now be able to clear more easily and at lower prices during scarcity periods.

There are three principal choices to be made in designing a capacity payment mechanism: (1) should the ITP require LSEs to contract bilaterally for resources or do the contracting itself and allocate its costs to LSEs; (2) where on the spectrum between "short term" (e.g., one day) and "long term" (e.g., five years) should the time horizon be chosen; and (3) should enforcement be *ex ante* based on forecasts or *ex post* based on what actually happens? Not all combinations of these choices are logical or workable, but any workable resource requirement/payment regime uses some combination of these options. The numerical parameters of the requirement or payment can be set so that the non-spot-market payments are higher or lower, resulting in more or less additional capacity and impact on spot prices.

If each LSE is required to contract bilaterally for resources, the ITP must define the MW requirement for each LSE, define criteria for resources that can meet this requirement, and enforce the requirements and criteria. If the ITP contracts directly with the resources itself, it must pick the specific resources, negotiate and enforce contracts with these resources, and allocate the costs to LSEs. Most existing ICAP programs and FERC's RAR rely on bilateral

[14] Capacity requirements are much less common outside the United States. For example, there is no such requirement in the ITP-like markets in England and Wales, Australia, New Zealand, Norway, Alberta or Ontario.

[15] The term "resources" includes both generation capacity and demand-reduction capability.

contracting by LSEs rather than centralized procurement by the ITP, but the latter is being considered in some ITP markets.

Existing ICAP programs put a short-term resource obligation on LSEs with both definition and enforcement of the obligation *ex post*. Each LSE's MW ICAP obligation is based on its peak demand during (say) a month as determined at the end of the month and any ICAP deficiencies or surpluses are priced in an ICAP market at the close of the month.[16] Defining and enforcing the obligation monthly and *ex post* makes it compatible with retail competition but may do little for investors or planners looking for assurance of supplies and revenues years ahead, or for consumers looking for long-term stability in monthly bills.

Long-term assurance of supply and long-term stability of monthly bills require multi-year resource commitments. In principle, the ITP could define the total resources needed (say) three years in advance and then require each LSE to contract or pay the ITP for its assigned share of that total three years in advance; but this is probably not realistic in a world of retail competition, where LSEs cannot forecast their loads years in advance.

With any of these (or other) alternatives, the size of non-spot resource payments and hence the impact on spot prices will depend on parameters such as the level of reserve margins and the enforcement penalties. These parameters could be adjusted to increase reliability and reduce spot scarcity prices as much as anybody could ever want – or more. For example, a monthly ICAP requirement with a 100 percent reserve margin would induce suppliers to make a lot of capacity available, even though they could lose money if they collectively built so much of it that both spot energy prices and monthly ICAP prices fell. Reliability would be high and spot prices would be low, but total costs would be high and the ITP's criteria, enforcement and cost allocations would be a major force in the market. The monthly reserve margin could be adjusted until an acceptable balance were found between high reliability and low spot prices on the one hand, and high costs and a strong ITP role on the other.

The fact that any effective resource requirement/payment creates some problems and inefficiencies does not mean that such a resource requirement/payment should never be used. The real world is full of unpleasant choices, and if high scarcity prices are politically unacceptable or are unlikely because of excessive MPM, some form of resource requirement/payment is required. The point here is that nobody should think that any such scheme is a costless way to keep scarcity prices down or to make up for suppressing them.

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[16] *Ex post* ICAP markets have proven to have highly volatile prices and have been accused of being susceptible to the exercise of market power. The basic problem is that the demand for ICAP in such a market is a simple multiple of peak demand in the month just ended while the supply of ICAP in the market may depend totally on equipment ratings and tests months earlier. With both demand and supply curves essentially vertical, the price is either zero or whatever price cap is imposed.

2.2.8 THE ROLE OF DEMAND RESPONSE

There is widespread agreement that electricity demand should and could be more price-elastic in the short run than it is, that ITPs should incorporate demand bidding into their dispatch and pricing processes, that there should be more use of time-of-use meters and demand management technologies, and that more consumers should be exposed to spot prices on the margin. But the fact that demand is not elastic "enough" is no reason not to let spot markets clear at scarcity levels, particularly when there is no way to know how much demand elasticity is "enough" and there are ways to clear spot markets even if market demand is not highly price-elastic. In fact, until spot prices reflect the true supply-side costs of meeting inelastic demand there will be too little incentive to make demand more price elastic.

Even in the absence of explicit demand bids from LSEs and large consumers, at least some demand will respond to expected spot prices, and the ITP should estimate and use this elasticity in forecasting demand in its dispatch and pricing processes. Interruptible load contracts imply some incremental cost of calling for an interruption,[17] and emergency actions such as taking energy from operating reserves, letting frequency or voltage drop or even shedding some load are logically high-cost demand reductions. In principle, all such actions should be given deemed bid prices and treated as demand bids – or supply bids; it can be done correctly either way – in the ITP's dispatch and pricing processes, along with sculpted supplier bids and the deemed costs of OOM actions.

3. FERC'S MARKET POWER MITIGATION PACKAGE

In the Notice of Proposed Rulemaking (NOPR) describing the SMD to be implemented by ITPs, FERC proposes a package of four MPM measures, three mandatory and one voluntary. The NOPR provides few details about these measures, but the general MPM framework proposed there will have a strong influence on the development of MPM procedures in all electricity markets, even those that may not adopt the full SMD.

3.1 OBJECTIVES OF THE FERC MPM PACKAGE

The SMD NOPR says that "the development of structurally competitive markets is the Commission's long-term goal," but that "at this stage of the industry's evolution" wholesale markets are not yet structurally competitive primarily because of "two significant structural flaws" in electricity markets: (1) "the lack of price responsive demand;" and (2) "generation concentration in transmission-constrained load pockets." [SMD NOPR, para. 390] This statement is significant primarily because it suggests both that FERC would be more relaxed about market power if ITPs were to take some of the steps suggested above to make demand

[17] A typical interruptible load contract may not specify an explicit cost to be paid when the load is interrupted but limits the number and/or cumulative effect of interruptions. Such a contract implies that interrupting load now has an opportunity cost, analogous to taking water from a reservoir.

for in-market energy more price responsive, and that FERC's current concerns about market power are limited to load pockets in which generation is so concentrated that workable competition is threatened.

The SMD NOPR also says: "the challenge for market power mitigation on the supply side is to assure that it allows long-term competitive prices, which allows the opportunity to recover the fixed costs of the investment as well as the short-term variable costs … If some degree of scarcity pricing is not allowed, … then some generators needed for reliability could fail to recover their full costs and may be retired. Worse yet, prices could be held so low that investors decline to invest … because they do not see a reasonable expectation of recovering their costs." [SMD NOPR, para 393] Thus, "the market power mitigation plan should be calibrated so that it does not inefficiently suppress prices, or mask scarcity prices, providing the wrong economic signals for efficient investment or demand response." [SMD NOPR, para. 397] These quotes imply that MPM should not suppress scarcity prices so much that average spot prices are less than LRMCs when and where investment is needed.

FERC's MPM mitigation package includes a mandatory resource adequacy requirement (RAR), justified with the statement that "the spot market does not yet work well to produce long-term reliability investment, even without price mitigation," because it takes a long time to build power plants and demand does not respond to price. FERC also justifies the RAR on the grounds that "market power mitigation may tend to suppress the scarcity price that would otherwise stimulate new resource development [and] as a result, investors may not develop adequate infrastructure …unless there is a provision for resource adequacy." [SMD NOPR, para. 468].

The most logical interpretation of the quotes above is that FERC does not want MPM to suppress scarcity prices below competitive levels but recognizes that this could happen and hence proposes the RAR to assure long-term resource adequacy given FERC's belief that the spot market is unlikely to do so. This is fine as far as it goes, but does not go far enough to explain how competitive prices should be defined and assured, or how the RAR can be made workable and effective.

3.2 Description of FERC's MPM Package

FERC's MPM package consists of the following four measures, the first three mandatory and the fourth voluntary.

3.2.1 Local Market Power Mitigation

Mandatory generator operating agreements (GOAs) between generators and the ITP will be used to mitigate local market power created by either "persistent and foreseeable" or "sporadic" transmission congestion. [SMD NOPR, para. 406] Each GOA will define the transmission system conditions under which that generator will be deemed to have local market power, and in those conditions the generator must offer all its available energy to the market either by scheduling it under bilateral contracts or by offering to sell it in the spot markets subject to a unit-specific bid cap.

3.2.2 Safety-Net Bid Cap

No supplier will be allowed to offer energy to ITP spot markets at prices exceeding an ITP-specified safety-net bid cap, such as $1,000/MWh, said to be necessary because of inadequate price-responsive demand. FERC says that imports offered at higher prices (subject to some higher bid cap) could set the market price above the safety-net bid cap, but also acknowledges that some OOM suppliers may receive higher payments without setting the market price. FERC does not say whether higher demand bids or (for example) the deemed cost of taking energy from operating reserves could set prices above the safety-net bid cap, but does not rule this out and even includes just such a mechanism in determining the spot-market compliance penalty in its RAR.

3.2.3 Resource Adequacy Requirement (RAR)

The RAR is described and analyzed in section 3.3.2 below. FERC regards its RAR as a MPM measure for two reasons: (1) Because the RAR is intended to induce LSEs to contract with generators for their full load and if they do generators will have less incentive to exercise market power in the spot market; and (2) because FERC recognizes that MPM may suppress scarcity prices so some other source of revenue for generators is required. As discussed below, something very different than the RAR outlined by FERC will have to be developed to accomplish what FERC wants.

3.2.4 Mitigation Triggered by Market Conditions

This fourth, voluntary MPM measure would presumably be some version of the automated mitigation (AMP) mechanisms "such as those approved by the Commission in New York ISO and California" [SMD NOPR, para. 231]. The MISO MPM proposal discussed in detail in section 4 below is the sort of thing FERC seems to have in mind.

FERC says this "measure, if needed, would apply to unanticipated and sustained market conditions that would give the ability and the incentive to exercise market power. For example, extreme supply or demand conditions to which the market cannot quickly adapt, such as … drought, or … a major transmission line outage. These kinds of events, which are not transitory, can provide opportunities to exercise market power even in a market that is normally workably competitive." [SMD NOPR, para. 415] Furthermore, "since this form of market power mitigation is for temporary market conditions, it will be equally important … to indicate the criteria to determine when the market has returned to normal competitive conditions and this market power mitigation method will be suspended." [SMD NOPR, para 416]

The quotes above would appear to limit the application of any AMP-like mechanism to unexpected, sustained but temporary periods of shortage, such as occurred in western power markets in 2000-2001. However, FERC also says that "it may be appropriate for other conditions to trigger this mechanism" and invites comment on what these triggers should be, suggesting that an ITP could ask FERC to apply such measures more broadly. [SMD NOPR, para. 415]

As to what this fourth measure is intended to accomplish, FERC says: "Although market-clearing prices would be expected to rise in these situations [to which this measure might apply], and perhaps sharply and significantly, … the market [may want] … the assurance that the price increases are attributable to the extreme circumstances and not to the exercise of market power." [SMD NOPR, para. 415] Again, the clear intent seems to be to assure that prices do not go significantly above competitive scarcity levels, but without suppressing prices below competitive scarcity levels in the short run and LRMC levels in the long run. Just how any MPM procedure is supposed to find this fine line, or how successfully it will do so, is not discussed.

3.3 Analysis of the FERC Proposals

The FERC MPM proposals are not defined in enough detail to allow detailed analysis of them, and until FERC decides what it will and will not approve it is not possible to say much about the likely effects. However, based on the general analysis above and on existing MPM procedures, including those approved by FERC in existing ITPs, the following general observations can be made.

3.3.1 The Effects on Scarcity Pricing

The safety net bid cap would apply at all times and places and would probably be set at something like $1,000/MWh. This level is low enough that it will suppress prices below competitive market-clearing levels during serious scarcity conditions, at least until ITPs implement scarcity pricing methods that can produce prices higher than any supplier's bid. FERC suggests that imports could set market prices higher than this bid cap but does not strongly endorse the development of other scarcity pricing mechanisms.

The measures for mitigating local market power included in generator operating agreements would be applied wherever "persistent and foreseeable" or "sporadic" transmission congestion creates local market power, which could be almost anywhere. The voluntary, AMP-like measure could also be interpreted to require widespread, even universal testing of market conduct in order to determine when and where some special market conditions are creating "unanticipated," "sustained" but "temporary" market power. Given that existing MPM procedures often misdiagnose and mitigate as exercises of market power the competitive market behavior that is needed to produce reasonable scarcity prices in today's ITP markets, widespread application of these tests and mitigation measures in search of market power to mitigate will tend to suppress scarcity prices.

3.3.2 The Resource Adequacy Requirement

In its introduction to the RAR proposal in the SMD NOPR, FERC asserts that spot prices – particularly when mitigated but even when not – cannot be relied upon to assure long-term resource adequacy, and criticizes existing ICAP arrangements, partly because of "concern about the[ir] effectiveness" and partly because they require the ITP to "play a strong role … that may not suit regions without a history of tightly coordinated reserve sharing." [SMD NOPR, para. 483] FERC then proposes a RAR that appears to be trying to find a "third way" that is neither scarcity pricing nor ICAP when, in fact, some versions of these are the only two logical alternatives.

The essential features of FERC's RAR proposal are the following:

- **Long-Term Resource Planning:** Each ITP, in cooperation with a Regional State Advisory Committee, use long-term – FERC says three-to-five years, but call it three years for discussion purposes – regional demand forecasts and resource projections, and a reserve margin of at least 12 percent, to "establish the appropriate level of resource adequacy for the region." [SMD NOPR, para. 491]

- **Allocation of the RAR Among LSEs:** The ITP will allocate the regional RAR among LSEs based on their individual peak demands; whether these should be actual past demands or forecast demands is one of the things on which FERC invites comments.

- **Resources That Can Satisfy the RAR:** Only contracts that meet specified criteria and require physical performance by real, identifiable resources can satisfy the RAR. The ITP will establish the criteria for resource performance and ISO contracts.

- **Enforcement of the RAR:** No LSE will be penalized for not contracting in advance for all (or any) of its allocated resource requirement. Instead, an LSE that does not meet its RAR in one year will be penalized three years later if it buys anything in the ITP's spot markets. The penalties will include a punitive surcharge over and above the spot price on spot purchases, plus an attempt to curtail the customers of deficient LSEs first if demand curtailments are necessary.

If FERC's RAR proposal were implemented as now proposed, it might create a long-term planning process but would provide no mechanism for implementing the resulting plan because the enforcement provisions are hollow – which would make the long-term planning process largely meaningless. Consider the enforcement provisions:

- **Curtailment of Customers:** The threat to curtail first the customers of LSEs who did not contract "enough" three years ago would be very difficult even to define and impractical to implement. With reasonably efficient wholesale markets the probability of involuntary curtailments is very small and with retail competition there is no practical way to target curtailments on the customers of specific LSEs.

- **Spot Market Penalties.** The threat to impose penalties on today's spot market purchases by LSEs who were deficient three years ago is very easy to avoid but creates real-time inefficiencies. Even if no LSEs contracted for anything three years ago, they can all contract enough sometime in the intervening three years (including yesterday) to avoid buying and paying penalties in the ITPs's spot markets. But whatever their contract portfolio of long-term and short-term contracts, each LSE must avoid taking either more or less than the specified contract quantities because contract imbalances are penalized.[18] The effect would be a form of contract dispatch that distorts real-time dispatch and consumption, increasing system and LSE costs.

The RAR as proposed in the SMD NOPR does little to assure long-term resource adequacy, because its enforcement is all based on what happens in short-term and real-time markets. Its penalty on spot purchases could be regarded as a way to get effective spot prices above some *de jure* or *de facto* cap on spot market prices, except that the spot-price-plus-penalty applies only to any LSEs who were/are deficient both three years ago and now, not to other LSEs or to suppliers. Any LSEs unlucky or incompetent enough to be in that situation will face incentives to reduce demand that are much higher than the demand-reduction incentives faced by other LSEs and much higher than the prices being paid to suppliers.

The most interesting part of the RAR proposal is that the penalty on spot purchases "would increase in stages as the shortage becomes more severe. For example, the penalty price could be $500 (in addition to the spot market energy price) when operating reserves are just below the minimum level, $600 when operating reserves are more than below 1 percent below [*sic*] the minimum level, $700 when operating reserves are more than 2 percent below the minimum level, and so on." [SMD NOPR, para. 530] Something similar should be used to determine a market price that applies to all LSEs and suppliers, not just a penalty that inefficiently and unfairly applies only to a few LSEs.

Long-term resource adequacy in electricity requires either efficient spot pricing, including scarcity prices that can be very high and are not subject to stringent caps or aggressive mitigation, or an effective resource requirement/payment mechanism to make up for the loss of scarcity prices due to price caps and mitigation. FERC has disparaged both of these options, but its proposed third way does not work; it will have to decide what combination of the two disparaged options it will support. Several such combinations are feasible, but will require accepting the reality of high scarcity prices, an effective capacity requirement/payment defined and enforced by a strong ITP, or some combination of the two.

4. THE MISO MARKET POWER MITIGATION PROPOSAL

The MISO is considering a MPM proposal being developed by Dr. David Patton, the MISO Independent Market Monitor (IMM) and the Independent Market Advisor to the New York ITP. This MPM proposal is similar to the AMP process used in New York and elsewhere, and is a relatively detailed example of the fourth, voluntary type of MPM measure proposed in FERC's SMD NOPR.

This section discusses the MISO MPM proposal, as described in a draft dated October 3, 2002 (the "MISO Draft"),[19] in terms of the economic principles outlined in section 2 above.

[18] It is unclear whether contract imbalances would be assessed on each of a LSE's individual contracts or on its portfolio. The former increases the operational inefficiencies and the latter gives an uneconomic competitive advantage to large LSEs.

The focus is on the definition and enforcement of the proposed prohibitions on physical withholding and bid caps for suppliers, because these are the most important features of the proposal. Silence on or cursory treatment of any feature of the MISO MPM proposal here means only that such feature has not been analyzed in detail.

This section also discusses a proposal by Dr. Patton that the energy price in the MISO spot market be very high when the ITP must take energy from operating reserves. This proposal and the reasons given for it, as well as similar recommendations that Dr. Patton has made to the New York ISO, are consistent with the ITP scarcity pricing recommendations made in section 2.2.4 above and are encouraging steps in the right direction, but would not solve all the problems with ITP pricing.

4.1 OBJECTIVES OF THE MISO MPM PROCEDURES

The MISO Draft stresses that the intent of the proposed MPM procedures is to "mitigate the market effects of any conduct that would substantially distort competitive outcomes" in the MISO markets, "while avoiding unnecessary interference with competitive price signals" [MISO Draft, sec. 1(a)] and while allowing "prices to rise efficiently to reflect legitimate supply shortages." [MISO Draft, sec. 1(b)] These assurances that MPM will not prevent prices from rising to scarcity levels are particularly critical given that there are apparently no plans to include a capacity requirement or payment in the MISO market, at least initially. Unfortunately, the MPM procedures outlined in the MISO Draft are unlikely to deliver on this promise.

The operational objective of the IMM in the MISO MPM proposal is to "remedy conduct that: (1) is significantly inconsistent with competitive conduct; and (2) would result in a substantial change in one or more prices" or production guarantee payments[20] in a MISO market [MISO Draft, sec. 2.3(a)]. This objective is noteworthy primarily for its focus on conduct that is "inconsistent with competitive conduct" as defined by the procedure itself and that causes "substantial change[s]" in prices in MISO spot markets however flawed the MISO pricing processes may be. As discussed in section 4.4.2 below, this inward focus on the procedure itself should be (at least) supplemented by efforts to evaluate and calibrate the MPM procedure in terms of its broader impacts on market outcomes, i.e., on average spot prices compared to LRMCs.

[19] Attached as Appendix A.

[20] Production guarantee payments are made to generators to cover the non-energy start up and other costs of a dispatched generator when spot market payments are inadequate to cover all such costs. The MISO proposal includes both conduct and impact thresholds related to these non-energy payments, but these are not discussed here.

4.2 Description of the MISO Proposal

The basic approach to MPM in the MISO Draft is the same approach used in functioning ITPs, endorsed by FERC and outlined in section 2.2.3 above. The specific definitions and procedures proposed for the MISO are summarized in this section.

4.2.1 Transmission Constrained Areas

The IMM will, at least once a year, identify any Narrow Constrained Areas (NCAs) within the MISO. A NCA is defined as an electrical area in which transmission congestion, however often it arises, can be "relieved" only by resources owned or controlled by (initially) "less than three" suppliers. [MISO Draft, sec. 2.5.1] This language suggests that the IMM will be able to draw lines around well-defined areas that are sometimes isolated from the rest of the grid by transmission constraints and count the suppliers within that area, but in practice things are seldom that simple. Many NCAs are likely to be a single node at which a single generator can sometimes increase the LMP with its own supply bid.

A Broad Constrained Area (BCA) is defined as any electrical area in which the conduct and impact thresholds defined below are violated. This language suggests that there is some distinction between a BCA and "the rest" of the grid, but in fact suppliers everywhere will be subjected to the same conduct and impact thresholds – except those in NCAs, which are subject to more stringent thresholds – and those who violate their thresholds in any given day or hour will have their bids mitigated. The intent and effect of the MISO MPM proposal would be clearer if the term "Broad Constrained Area" were dropped and replaced with some version of "anywhere" or "everywhere" wherever it appears in the MISO Draft.

4.2.2 Bidding Reference Levels:

Reference levels will be set in advance for each component of a generator's bids, such as the energy price ($/MWh), start-up costs ($/start-up), minimum run times (hours), etc., at levels "intended to reflect a resource's marginal costs, including legitimate risk and opportunity costs." [MISO Draft, sec. 3.1.4(a)] Reference levels for each generating unit will be determined by the IMM using one or more of several methods: past bids or prices during periods when the unit is presumed to have been bidding its "true" SRMC, i.e., when bids or prices were low and the unit was dispatched; negotiations with the unit operator; IMM estimates of costs; or comparison with competitive bids from similar units.

Reference levels for energy prices ($/MWh) can vary with energy output "over the output range of the resource," but there is no indication that sculpted SRMC bids reflecting a generator's judgment about the very high costs and risks of the last few MW are contemplated or would be allowed. The IMM will inform each market participant of the reference levels applicable to its units and market participants may request changes in reference levels. The MISO will have dispute resolution procedures and market participants can ultimately appeal to the FERC if they disagree with the reference levels determined by the IMM.

4.2.3 CONDUCT THRESHOLDS

The bid parameters and offered capacity of all suppliers will be tested to see if they violate conduct thresholds for economic withholding or physical withholding. There are minimally stringent conduct thresholds that apply everywhere and additional thresholds that apply to a supplier in a NCA when they more stringent than the minimally stringent thresholds. The conduct thresholds relevant for the discussion here are:

- **Conduct threshold for economic withholding**: A supplier violates its economic withholding threshold if its bid parameters exceed its reference levels by more than:
  - For an energy bid (energy bids less than $25/MWh are exempt): The lesser of 300 percent or $100/MWh or (for a supplier in a NCA when constraints are binding) a "NCA Threshold" discussed further below and defined as:

    NCA Threshold = (Net Annual Fixed Cost)/(Constrained Hours)
  - For a start-up cost bid: 200 percent, reduced to 50 percent for a supplier in a NCA
  - For time-based parameters (e.g., minimum down-time): 3 hours for any single parameter or 6 hours in total for all parameters
  - For bid parameters expressed in units other than time or dollars: A 100 percent increase for parameters that are minimum values, or a 50 percent decrease for parameters that are maximum values.
- **Conduct threshold for physical withholding:** Physical withholding is defined to include not-offering a unit's "capability" without good reason, economic withholding as defined above, and operating a unit at less than a dispatched level. For suppliers within a NCA, any physical withholding, however small, is a violation of the threshold. A supplier anywhere outside a NCA violates its physical withholding thresholds if it:
  - Withholds more than the lesser of 10 percent or 100 MW of a unit's capability;
  - Withholds more than the lesser of 5 percent or 200 MW of its total capability; or
  - Operates at less than 90 percent of a dispatched output level

4.2.4 MARKET IMPACT THRESHOLDS:

If a supplier violates any applicable conduct threshold above, the impact of the violating behavior on market outcomes will be tested, presumably using procedures similar to those used elsewhere by Dr. Patton. In these procedures, the IMM will use the MISO's market rules and models to determine what market outcomes would have been if everything in the market remained the same except that all bid parameters that violate a conduct threshold are simultaneously[21] mitigated to their reference levels, e.g., to simple MCs for energy bids. A supplier that is in violation of any of its conduct thresholds is also in violation of the market

[21] An alternative interpretation is that each bid parameter that violates a conduct threshold would be tested individually for its market impact, leaving all other such bid parameters at their as-submitted, unmitigated levels. This interpretation would significantly reduce the impact of MPM but seems unlikely.

impact threshold if this test finds that, as a result of all suppliers' conduct violating thresholds:

- Any price in a MISO market increases by more than the lesser of 200 percent, $100/MWh or (for a supplier in a NCA) the NCA Threshold defined above and discussed below.
- A daily guarantee payment to the supplier increases by more than 200 percent.

4.2.5 Prospective Bid Mitigation

When the conduct of a supplier violates any applicable conduct threshold and the market impact of all such conduct violates an impact threshold, the following mitigation measures are applied.

- **Price Mitigation:** If the conduct that violates a conduct threshold relates to a bid parameter, the MISO will substitute for the violating bid parameter a default bid parameter equal to the reference level for that bid parameter. This substitution will be done prior to determining market prices, which means it must almost certainly be done in a computerized AMP procedure; prices will not be mitigated *ex post* except as may be specifically authorized by FERC. The resulting mitigated prices shall apply to all market participants, whether or not their bids have been mitigated.

- **Financial Sanctions:** If the conduct that violates a threshold was physical withholding or any other activity that cannot realistically be prevented or mitigated before the fact, the violating market participant will be subject to a financial penalty equal to the LMP at the most relevant location(s), multiplied by the MW withheld, multiplied by a penalty factor that increases the more often the market participants is guilty of withholding.

The MISO Draft also proposes provisions intended to remedy and discourage actions that are inconsistent with competition and that create undesirable divergence between day-ahead and real-time prices, but these are not discussed here.

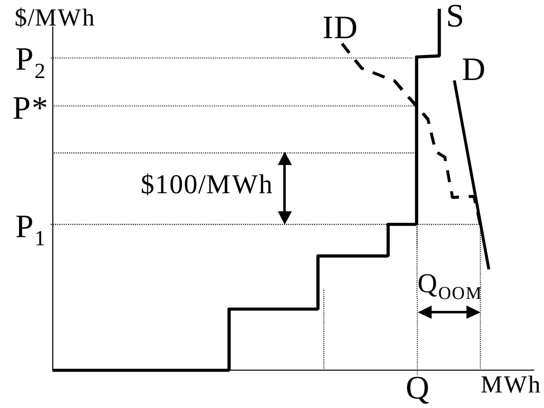
4.3 Effects of the MISO Proposal

This section discusses the likely effects of the MISO proposal and Dr. Patton's suggestion to improve scarcity pricing in the MISO spot market.

4.3.1 The Suppression of Scarcity Prices

The MPM procedure proposed for MISO (and used elsewhere) suffers from the logical inconsistency discussed in section 2.2.3 above: Reference prices are set based on how competitive suppliers would bid if the ITP determined scarcity prices properly, but then suppliers are (in effect) required to bid that way even though the ITP does not determine scarcity prices properly. The inevitable result is a suppression of scarcity prices, with all this implies about short-run efficiency, the effects on investment incentives, the need for a resource requirement/payment, etc.

Figure 9:
Suppression of Scarcity Prices



This is illustrated in Figure 9, where it is assumed that the marginal in-market generator – call it a "peaker" – has a simple MC or reference price of P_1 and a conduct threshold of $100/MWh. If the market demand curve for energy is D and the MISO's implicit demand curve for in-market energy is ID, the true scarcity prices is P*. If the peaker bids its reference price of P_1, the MISO will set the market price at this level and will call on Q_{OOM} MWh of OOM supplies to meet demand, but does not let the high costs of these OOM supplies set the market price. The result is inefficient, because high-cost supplies are being used to meet demands that – according to the market demand curve – value the energy at less than it costs. The result is also unfair and, if it happens very often, unsustainable, because the peaker and all other generators are being paid less than the true competitive value of their energy and less than they should get as a contribution to their fixed costs.

If the marginal generator increases its bid price to P* – and this bid is not mitigated – the MISO will set the price at the market-clearing level P*. This would be a good thing for all concerned – even consumers in the long run – because it would allow some in-market demand response and other market-drive actions to replace some higher-cost OOM energy, and because it would allow the marginal generator and all others to earn a competitive operating profit or rent that helps pay fixed costs.

Under the MISO MPM procedure, however, a peaker bid price of P* would violate the conduct threshold, and (as drawn in Figure 9) then the impact threshold, and hence would be mitigated down – not just to the allowed maximum bid/price impact of P_1+$100/MWh, but all the way down to P_1. The ITP would then set the price at P_1 and use high-cost OOM energy to meet the excess demand at that price.

This type of mitigation will effectively limit bids to levels that will not violate conduct thresholds, because bidders will not want to risk being mitigated all the way back to their reference bids, and hence will often result in prices that are far below market-clearing levels. One change in the mitigation rules that might help in situations such as this would be to mitigate an energy bid down to the conduct threshold, not to the reference bid, when both conduct and impact thresholds are violated. This would allow the peaker to bid more aggressively when it expects the real scarcity price to be very high, with less risk of having its bid mitigated down to the reference level and losing everything.

The MISO Draft recognizes that the proposed procedure will suppress scarcity prices, so it proposes that suppliers in NCAs be allowed to bid above their simple MCs or reference prices by an amount that is apparently intended to give them a chance to recover their fixed costs. Furthermore, Dr. Patton has recommended some changes to the MISO pricing rules that could, under some conditions , result in scarcity prices that exceed any supplier bids. As discussed in the next two sections, however, these proposals, as welcome as they are, are not enough to eliminate, or perhaps even significantly to reduce, the tendency of this procedure to suppress scarcity prices.

4.3.2 Treatment of Suppliers within Narrow Constrained Areas

In the MISO Draft, a supplier within a NCA is, under some conditions and to some extent, allowed to bid energy prices that exceed its simple MC by an amount related to its fixed costs without such bidding violating its energy bid conduct threshold. This is noteworthy because it implicitly acknowledges that the MISO spot markets will not reliably produce scarcity or compensatory prices unless suppliers bid such prices. However, the provision as it stands will not necessarily accomplish its apparent objective for both theoretical and practical reasons.

The theoretical problem is in the definition of the "NCA Threshold" that limits both the (maximum) amount by which the supplier is allowed to bid above its SRMC and the amount by which the market price is allowed to increase. The NCA Threshold is defined as follows:

$$\text{NCA Threshold} = \frac{\text{(Net Annual Fixed Cost)}}{\text{(Constrained Hours)}}$$

where:

Net Annual Fixed Cost	=	"Annual fixed costs of a new peaking generator per MW, including recovery of capital costs, minus appropriate credits for Net Revenue the new peaking generator would receive from the MISO electricity market." [MISO Draft, sec. 3.1.2(c)(1)]
Constrained Hours	=	The number of hours over the prior 12 months in which imports into the NCA were constrained, but not more than 2,000 hours

The problem is that it is theoretically incorrect to use a peaker's annual fixed costs in the definition of the NCA Threshold unless the generator subject to that threshold is itself a peaker. If a generator is to recover its total costs with a price that has two components, one related to energy costs and the other related to fixed costs, the two components must relate to the same kind of plant. As both a logical and a practical matter, a generator in a NCA should be allowed to bid its own energy costs plus its own fixed costs (or perhaps the fixed costs of a proxy plant of the same type). It is mixing apples and oranges to say that a non-peaker generator can recover its own energy costs plus a peaker's fixed costs. For example, if the generator at issue is a baseload plant, prices equal to its own low fuel costs plus the low fixed costs of a peaker will not cover its full costs.

Other, less theoretical problems with this provision may be more important in practice, particularly if the generator in question is a peaker. Even if the NCA Threshold is defined correctly, a generator may not be able to bid at the implied level because a generator's conduct threshold is the ***minimum*** of the NCA Threshold, $100/MWh or 300 percent of the generator's reference energy price, so if the NCA Threshold is very high the generator cannot bid it. For example, if the Net Annual Fixed Cost of a Peaker is $80/kW-year and there were 500 constrained hours last year, the NCA Threshold is $160/MWh, which is greater than $100/MWh, so the effective conduct threshold is $100/MWh, not the NCA Threshold. If the purpose of the NCA Threshold is to give supplier in a NCA a better chance to recover its fixed costs, the effective threshold should be the NCA Threshold, period.

Furthermore, even if the generator can bid the NCA Threshold in all constrained hours, it is unlikely that doing so would result in a price at this level in all hours. If the market price were lower than the price defined by the NCA Threshold in some of the constrained hours, a generator under this bidding constraint would be unlikely to recover its fixed costs even if the average market-clearing price P* over constrained hours would do so.

4.3.3 The Patton Reserve Pricing Proposal

In a memorandum to the MISO Operating Reserves Task Force dated October 29, 2002 (the "Patton Memo"), Dr. Patton has recommended a mechanism for "establishing economically efficient energy prices during capacity shortages (i.e., when there is insufficient capacity to meet both the energy and operating reserve requirements of the system)." The reasons given in the Patton Memo for this recommendation are similar to the arguments in this paper: "[I]f the market rules are developed without an explicit economic relationship between the reserves and energy markets, spot energy prices that are determined during the capacity shortage are likely to not reflect the full value of energy. By muting energy prices during shortages, the market will not send appropriate signals in the short-run for resources to enter from other regions nor send efficient signals over the longer-term for new investment." [Patton Memo, p. 1]

Dr. Patton's recommendation and arguments here, and similar things he has proposed for the New York ISO, are consistent with the recommendations and arguments in this paper and are certainly a step in the right direction, But they are not enough to remedy the deficiencies in ITP pricing even if implemented, largely because they would add only one large and seldom relevant step to the supply curve, when what is needed is a whole series of steps that can routinely set scarcity prices.

Simply stated, Dr. Patton recommends that activation of reserves by the MISO be treated as an addition to market supply with an energy bid equal to or above the level of FERC's safety-net bid cap and that this reserve energy bid be used to determine prices. The justification given for setting the minimum price of reserve energy at the safety-net bid cap is that reserves should not be activated until all supply bids are taken. In principle, such a rule for reserve activation is not required or necessarily optimal; it might be better to release small amounts of reserves at prices that are high but less than the safety-net bid cap. Be that as it may, the Patton Memo recommends putting a bid floor on operating reserves at the safety-net-bid cap, call it $1,000/MWh for concreteness.

Given that the marginal suppliers are likely to be CTs with a reference energy bid price of no more than about $100/MWh and a conduct threshold of no more than $100/MWh (or less, for a peaker in an NCA with a lower NCA Threshold), the effective limit on energy offer prices from suppliers will be about $200/MWh – 20 cents/kWh – leaving a very big gap between the highest supplier bids and the minimum bid price for reserve activation. For example, if P_2 in Figure 9 represents the safety-net bid cap/minimum reserve bid and P_1 is the highest simple MC of any supplier, there is a large gap between P_1 and P_2 and there will many hours when the market-clearing price is somewhere in between. If suppliers are allowed to submit sculpted bids for small amounts of energy at high prices, there may be some supplier bids in that range, but there is no guarantee this will be the case everywhere, e.g., in a small area or single node designated a NCA.

A critical issue is what happens if/when the market-clearing price is above the highest supply bid but below the reserve activation bid at (e.g.) $1,000/MWh, which is likely to be common in non-emergency scarcity conditions. If demand expects a price of P_1 there will be excess demand at that price, which the MISO will have to meet using OOM actions other than activating reserves. If these actions do not set the price the pricing problem has not been solved by putting in the very high and rarely used bid at P_2.

One possible solution to the "large gap" problem would be to develop a formula that would set the market price at a weighted average of P_1 and P_2, with the weights depending on how much OOM energy is needed to close the gap. This would not be necessary if the MISO's implicit demand curve for in-market energy ID were really known, but in practice it probably will not be. What the MISO will know is whether, after taking all the supplier energy available at price P_1, it had to use a lot or a little OOM energy to meet demand and how close it came to activating reserves. The market price should be a continuous function of such operational factors between P_1 and P_2.

Again, if all this sounds too hard and *ad hoc* to be realistic, the implication is that the MISO will not really have a very good scarcity pricing mechanism, and the only way to get reasonable approximations of scarcity prices is to let suppliers bid at least some non-trivial amount of their energy at their estimate of the scarcity price without it being regarded as an exercise of market power that must be mitigated. As long as such bidding behavior does not result in time-average spot prices that are significantly above the supplier's total costs or the LRMC of similar suppliers, the supplier is not benefiting from any exercise of market power but is simply bidding as it must to get the prices it deserves given the deficiencies of the MISO's pricing process.

4.4 Evaluation of the MISO Proposal

The proposed MISO MPM procedure is similar to the AMP procedures currently used in ISOs/ITPs and endorsed by FERC in its SMD NOPR. As such, it is worth evaluating the MISO proposal in terms of its apparent consistency with FERC's SMD objectives and the logic of its basic approach.

4.4.1 Consistency With FERC's SMD NOPR

The treatment of Narrow Constrained Areas in the MISO proposal corresponds closely to the local market power mitigation measure mandated in the SMD NOPR, although FERC proposes that this measure be applied through Generator Operating Agreements. MISO's proposed treatment of Broad Constrained Areas is harder to put into the FERC framework and, in fact, appears to be inconsistent with at the least the spirit of FERC's proposals, because MISO would apply the MPM thresholds and, if so indicated, the mitigation measures everywhere and at all times, not just in special, clearly defined circumstances.

FERC says that its voluntary AMP-like measure is to be applied only in "unanticipated and sustained" but "temporary" market conditions such as a drought or major transmission line outage, and with clear "criteria" for determining when such special conditions exist and when they have ended. It might be argued that the threshold tests are these "criteria," and that they must be applied at all times and places because there is no other way to know where and when they are being violated. But this would seem to be inconsistent with FERC's clear intent to leave the market alone except under unusual circumstances.

Universal application of the thresholds might be defended as a way, or even the only practical way, to determine when and where "sporadic" transmission congestion is creating local market power. But this is casting a very large and heavy net just in case there are a few fish out there and without regard for the effects on the innocent dolphins. This, too, would appear to be inconsistent with FERC's intent to leave the market alone unless there are clear indications of a problem that needs fixing.

4.4.2 Circularity and Self-Verification

The MISO proposal contains many numbers – 200 percent here, 300 percent there; \$100/MWh here, \$25/MWh there – that, taken together, will determine whether the MPM procedure will be ineffectual or draconian or somewhere in between. None of these numbers has been or realistically could be chosen based on either sound theory or quantitative analysis. At best they reflect judgments about what is "reasonable" based on very little experience.

Any new policy or procedure is implemented without knowing precisely what its effects will be and with the understanding that it may have to be adjusted based on experience with it. But for experience to be useful there must be clear guidelines stating what the procedure is intended to accomplish, how its performance will be measured and evaluated, and how it might be changed in response to experience. The MISO Draft does state the objective of the MPM procedure: to "allow prices to rise efficiently to reflect legitimate supply shortages while effectively mitigating inflated prices …" [MISO Draft, sec. 1(b)] But without some objective way to determine when mitigated or unmitigated price levels are high enough "to reflect legitimate supply shortages" without being "inflated" there is no way to know when or if the procedure is accomplishing its stated objective.

The MISO MPM procedure, like all AMP-like procedures, implicitly assumes that the right competitive price in an ITP's market is the price resulting from application of the MPM procedure in that ITP's market, and hence here is no need – or even no way – to compare the prices resulting from application of the MPM procedure to some external estimate of competitive prices. Even if AMP-like procedures did not suffer from the serious logical problems discussed in section 2.2.3 above, such circular self-verification would be illogical and potentially dangerous.

Before adopting the proposed (or any) MPM procedure, the MISO and FERC should require the development of a plan for evaluating the impact of the procedure, calibrating it so that it does what it is supposed to and nothing else, and modifying or deactivating it as appropriate. Such an evaluation/calibration plan should look beyond specific hourly prices and outside itself for evidence that it is or is not doing what is intended. Evaluation should be based primarily on comparisons of time-averaged spot prices to the LRMCs of needed generation. The calibration procedure should adjust the parameters to assure that the interactions of the MPM procedure and the realities of the spot market do not suppress average spot prices below LRMCs and should deactivate the whole procedure unless there is clear evidence that without it average spot prices would be too high.

5. A SUGGESTED APPROACH TO MARKET POWER

The analysis of economic principles and current practice in the preceding sections suggests the following general approach to the identification and mitigation of market power in electricity spot markets.

5.1 Keep Spot Market Power in Perspective

Most consumers and in fact many suppliers and middlemen do not care what the spot price is in any specific hour or how much it may change from hour to hour, because they will not or cannot respond to hourly spot prices and because they (at least should) do most of their business under contracts and price-averaging arrangements; what these players care about are average spot prices over periods ranging from a day to a year. But for those who do care about prices over shorter periods because they can respond to them, it is important that the prices to which they respond reflect the real value of energy at that time. Artificially suppressing scarcity prices increases costs for everyone and does no good for anyone in the long run.

Given the difficulty of knowing precisely how a competitive supplier should behave in a spot market or what the “right” competitive spot price is, it is a serious mistake to try to identify and control market power by observing either behavior or outcomes in individual spot market periods, i.e., hours in the case of electricity. If suppliers are effectively exercising market power in spot markets, it will show up in time-averaged prices over periods such as a year or more. If such average spot prices are not above the LRMC levels needed to stimulate needed investment, there is no good reason to implement comprehensive, intrusive and potentially distorting procedures for identifying and mitigating market power in spot markets and many good reasons not to do so.

The evidence from functioning ITP spot markets is that suppliers are not making too much money in those markets, and in fact may be making too little. For example, Dr. Patton says that spot prices in New York, even after ICAP payments, “would not likely support new investment in GTs” [gas turbines] outside New York City “with significant uncertainty regarding GTs within" New York City."[22] A similar analysis for gas-fired combined cycles plants in New York and New England indicates that average spot prices were below LRMCs even during 2000-2002 when the supply-demand balance was very tight.[23] Such results do not suggest there is a compelling need to implement aggressive or comprehensive MPM procedures at this time.

5.2 Improve ITP Spot Scarcity Pricing

Much of the behavior that is viewed as an exercise in market power in ITP markets can be explained at least as well as the necessary behavior of workably competitive suppliers given that the ITP markets do not have the kind of scarcity pricing procedures they should have – and that they are likely to be assumed to have when reference levels are set in AMP-like MPM procedures. If ITP scarcity pricing is improved, there will be less need for competitive suppliers to act in ways that are commonly, if incorrectly, interpreted as an exercise of market power, and it will become less difficult to identify and remedy true exercises of market power.

ITP pricing processes can be improved by basing scarcity prices on sculpted supplier bids, demand bids, the costs of imports and recalled exports, and the implicit costs of what are now treated as out-of-market actions. Dr. Patton's suggestions along these lines for the New York ITP and for MISO are a step in the right direction that should be adopted and extended; but even if these specific steps are implemented, ITP markets will not establish efficient scarcity prices if all suppliers are required to bid at their simple MCs.

5.3 Keep MPM Focused and Light-Handed

Given that ITP markets do not have good scarcity pricing and that the market evidence does not provide compelling or even a plausible case for aggressive and comprehensive MPM procedures at this time, efforts to control market power should focus on identifying specific, localized problems and tailoring specific programs for these. Even where specific problems are identified, it should not be assumed that AMP-like procedures are the only or the best solution. Indeed, the preferred approach should be structural and contractual remedies, such as contracts that reduce the incentive to drive up scarcity prices, rather than intrusive efforts to control market behavior and outcomes directly.

Where comprehensive MPM procedures are implemented, they should be carefully calibrated so that they mitigate egregious behavior and outcomes without interfering with the normal efforts of suppliers in complex and imperfect ITP markets to remain commercially viable. MPM procedures should not apply mechanical measures of what competitive suppliers

[22] David B. Patton, PhD, "Summer 2002 Review of the New York Electricity Markets," presentation to the New York ITP Board of Directors and Management Committee, October 15, 2002.

[23] See Klein, Abram, "Scarcity Pricing in Northeast ISOs: An Assessment of Market Performance," Presentation for NECA Wholesale Markets Conference, November 14, 2002, Boston, MA.

would do in a perfect ITP market and then compel such behavior in real ITP markets where it produces much lower prices than it would in a perfect ITP market. Instead, MPM procedures should ask what workably competitive suppliers would, indeed must, do to survive in real ITP markets, and then not prevent such commercially sensible and necessary behavior until there is some better way to assure the commercial viability of needed suppliers.

5.4 Use Capacity Payments To Offset Aggressive MPM

Aggressive MPM procedures will inevitably suppress scarcity prices. At least if and while such aggressive MPM procedures are in place, some effective form of resource requirement or payment is required. The basic choice to be made here is whether the time horizon for such a program should be short-term or long-term. A short time horizon – e.g., a month or so, like most ICAP programs – can reduce and stabilize spot market prices but will not give much assurance to those who want to see long-term commitments and long-term price stability. A long time horizon – e.g., three-to-five years, as proposed for FERC's Resource Adequacy Requirement (RAR) – can produce long-term commitments and stability, but only if the ITP makes long-term plans and then either makes itself or effectively compels LSEs to make long-term commitments.

FERC appears to be trying to avoid the fundamental logical choice between efficient spot markets with good scarcity pricing and an effective resource requirement/payment mechanism. Its RAR proposal is neither of these nor even a logical combination. FERC will have to develop something different and much better, particularly if FERC endorses and approves aggressive MPM procedures.

5.5 Move Quickly To Full Competition with Good Scarcity Pricing

The long-term objective for competitive electricity markets should be, as FERC says, "the development of structurally competitive markets." An important step in accomplishing this objective is good scarcity pricing in spot markets, because such pricing is necessary to reduce concerns about market power and the need for MPM procedures, and to reduce the need for the ITP to make decisions that should be made in the market.

Conversely, and just as importantly, if intrusive and distorting MPM prevents or delays good ITP scarcity pricing, concerns about market power will be perpetuated, there will be continued demand for aggressive regulatory interventions and ITP decision-making that distort market dynamics, and the development of structurally competitive markets will be delayed. Good pricing by ITPs is not a substitute for structurally competitive markets or *vice versa*; the two go hand in hand or not at all.

ATTACHMENT 5

GOVERNMENT INTERVENTION INTO WHOLESALE ELECTRIC MARKETS TO ASSURE GENERATION ADEQUACY

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November 6, 2002

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GOVERNMENT INTERVENTION INTO WHOLESALE ELECTRIC MARKETS TO ASSURE GENERATION ADEQUACY[2]

By: Mark Reeder

November 6, 2002

Introduction

There has been much discussion in recent years about wholesale electric markets and the need for a better market design to ensure the adequate reliability of wholesale electricity systems.[3] It is generally agreed that the existing market designs for Installed Capacity (ICAP) markets have not worked well and/or are not likely to work well. In this paper, I start by taking a step back and examining how markets in general, in products other than electricity, naturally yield reliability levels. This exercise is valuable in providing a perspective for evaluating mechanisms designed to assure electric reliability, and to understand the limitations involved in establishing such mechanisms. Next, after taking a brief look at the facts and figures regarding capacity reserves in New York at this time, I briefly reiterate the original impetus for creating the ICAP markets at the time of electric deregulation. I then turn to the specifics of the existing New York market design and describe its now well-known weaknesses. This is followed by a description of NYPSC staff's recent proposal for a Resource Adequacy Assurance Mechanism (RAAM).

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[2] Based on a presentation made at the Multiple Intervenors' 30th Anniversary Annual Meeting, October 3, 2002, Syracuse, New York.

[3] In this paper, the term "reliability" is used repeatedly. It is being used loosely to generally encompass the concept of "generation adequacy." Engineers tend to use the former term as a short-run measure of the electric system's ability to withstand shock, and the latter as a measure of medium-run and long-run ability of the system to possess sufficient generation capacity. For ease of discussion, this paper will use the term reliability to refer to what engineers prefer to call generation adequacy.

The Role of Entry in Driving the Outcome of a Natural Market

Any businessman knows well the importance of entry and how it drives the results of the marketplace. Ultimately, it is the cost of new entrants that determines overall price levels and it is the amount of new entry, and exit, that determines the reliability of service seen by a buyer in the marketplace. If prices are high relative to the cost of new entry, new entrants will be attracted into the marketplace, and prices will be pulled back down. If prices are low compared to the cost of new entry, there will be little or no new entry, exit may occur due to the inability to make a reasonable profit, and prices will be pushed up. The process of prices affecting entry, and entry affecting prices, yields an equilibrium price that is tied to the cost of entry. Over time, prices will fluctuate up and down in cycles of several years, even many years, depending on the industry, with the price gravitating toward and fluctuating around the cost of entry.

The very same process also yields a natural level of quantity, also known as reliability. It is often the relative scarcity of a product that pushes its price up, and, at the point where the degree of scarcity yields a price that is just right, i.e., equal to the cost of new entry, the natural level of reliability in that marketplace is established. For example, consider the market for hotels in New Orleans. In equilibrium, hotel rooms are prevalent during off-peak periods, but are in short supply during peak periods, such as during Mardi Gras. During a peak period, prices are pushed up and the ability to obtain a hotel room is difficult, if not virtually impossible. The overall annual revenue stream of a hotel operator is greatly enhanced by high prices during peak periods, and there needs to be at least some of these high-priced peak periods (often accompanied by shortages) in order to boost the overall annual revenue stream to a level that adequately compensates the hotel operator for its annual fixed cost. In its natural equilibrium, the hotel market yields an overall annual price level that matches the cost of new entry and overall reliability level that falls out naturally as part of the market. Virtually all markets for capital-intensive products and services use this process to yield the two outcomes of price and reliability.

<u>The New York State Capacity Reserve Situation</u>

According to the NYISO Gold book,[4] the generation reserve margin for New York State (NYS) as a whole in 2002 equals 23%. This is 5% above the minimum level of 18%. The 18% minimum equates to the commonly used reliability target of one shortage per 10 years. Given a NYS peak load of about 30,000 MW, each percentage point of the reserve margin equates to 300 MW. The current 5% excess reserve level equals about 1,500 MW.

Quite recently, NYS was described as a state with a tight capacity reserve environment. The relatively flush current environment is due to three factors: (1) the installation of new New York Power Authority Turbines in summer 2001 (440 MW); (2) the installation of new generation on Long Island (400 MW); and (3) the change in rules that enabled Special Case Resources (SCR), which are either generation behind the meter or demand reduction, to qualify as providers of generation capacity (530 MW). Load growth is currently forecast to be about 500 MW per year; this means the current excess reserves are good through the end of the summer of 2005.

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[4] New York Independent System Operator, <u>2002 Load and Capacity Data</u>, filed with the New York State Energy Planning Board pursuant to Section 6-106 of the New York State Energy Law.

Is NYS in trouble in the post-2005 time frame, as regards sufficient capacity? The answer depends on several new plants that are under construction. The Athens Plant upstate is scheduled to come on-line in 2003 and equals 1,080 MW. It is over halfway constructed and is expected to be completed, although doubts have surfaced recently. The Bethlehem project, which represents a net increase of 350 MW, is scheduled to come on on-line in 2006. The Ravenswood expansion, scheduled for late 2003, represents 250 MW. Finally, the East River Project, a net 200 MW addition, is scheduled for 2004. These three plants taken together add up to 1,880 MW. Assuming that all four plants come on-line, NYS, as a whole, has adequate generation capacity through the year 2008.

The excess supply has affected New York's ICAP market. It has caused market clearing prices for upstate ICAP to drop to very low levels, below $1.00/kW-month for the winter of 2002-2003. The average market clearing price for the most recent 12 months has been about $1.00. This compares to estimates of the cost of new entry for a combustion turbine that are in the $5 to $10 range. Energy market prices are also depressed by the 5% excess capacity, although not nearly to the extent that the ICAP market is.

The above picture appears to be a reasonably comfortable one from a resource adequacy perspective. There is a wild card in the story, however. That is the assumption inherent in the discussion that all of the existing plants will stay in business. A problem is that at the current very low ICAP price level, the continued operation of at least some of NYS's weakest plants is in doubt. The Oswego plant, for example, is a 1700 MW facility in upstate New York that was designed as a baseload plant, but hardly ever runs due to poor heat rates and high fuel costs (its capacity factor for 2001 was 3%). It is doubtful that this plant is making money at today's ICAP prices. The Bowline Plant in the Hudson Valley, a 1200 MW plant, is also a fairly high-cost plant that has a fairly low capacity factor (16% in 2001). It may not continue to be viable at existing depressed ICAP prices. These two plants combine for 2900 MW, which, if subtracted from existing supplies, would bring New York into an immediate deficit. The importance of this point is that, while many talk about the need to see ICAP price levels high enough to support new entry, there is also the concern, perhaps a very real one, about the need for ICAP prices to at least remain above some minimal level necessary to keep existing plants viable. Of course, the retirement of old and inefficient plants is a normal thing in all markets, and it would be wrong to assume that this phenomenon should be prevented. Nevertheless, in examining markets for generation capacity, it is important to consider the possibility of retirements. This concern is magnified when one sees that a fairly small capacity surplus can depress ICAP prices so much so that retirement could then immediately eliminate the entire surplus. As will be discussed more fully below, there is a need for the market to provide a more stable price signal for generators so that dramatic price crashes that threaten retirements are minimized.

As for the current low ICAP prices upstate, they cannot last. No market can operate over the long term at prices that lie below the cost of new entry. In the long run, prices must equilibrate around the cost of new entry. There is no way around that, and there is no point in attempting to pursue policies that would buck the force of the economics of the market and try to permanently hold prices down.

Why Intervene in the Electricity Market?

At the onset of electric deregulation in the United States, policymakers were concerned about whether the electric marketplace would naturally yield reliability levels as high as those that policymakers and electric users had grown comfortable with under the status quo. The obvious default approach was to simply let the market operate naturally, without intervention, i.e., no generation adequacy requirement and no ICAP market. Under such an approach, as discussed above, entry and exit would occur and the market would reach its own natural equilibrium. The result would be energy market prices that just cover the cost of entry and a natural reliability level.[5] It is important to remember that in the wholesale electric market, as in any other market, if prices are too low to encourage new entry, the mechanism that raises prices is the lack of entry (and retirements), which tightens the market, drives up energy prices, and lowers reliability. As such, prices and reliability are the opposite sides of the same coin; to increase the former, the market needs to lower the latter.

Policymakers, at least in the northeast, rejected the natural approach. Not knowing what level of natural reliability was likely to emerge, it was decided to ensure that a minimum level of reliability was maintained (an 18% reserve margin in New York, which is consistent with the one day in ten years reliability standard). Electricity was thought to require a treatment that differs from many of society's other, less crucial, products. For example, society tolerates the market's natural outcome in which several weeks a year people have to be turned away from hotels because they are sold out. It is not as acceptable to have the electric system turn electric users away with the same

[5] Ancillary services markets would provide an additional revenue stream, but are ignored to keep the discussion simple.

frequency because of electric shortages.[6] Given this concern, the policy decision was made to intervene in the natural marketplace to produce an altered outcome.

Intervention does have its consequences, however. The extra generation capacity associated with a required reserve margin affects the energy market. It depresses annual energy market revenues for all generators, which in turn leads to the need for an alternative revenue stream via some kind of generation capacity payment mechanism.[7] This extra revenue stream enables the market to entice more entry than would otherwise occur, thereby achieving the goal of enhanced reliability.

It is useful to think of a capacity market mechanism as a government-mandated "thumb on the scale" that puts more revenues into the mix for those that are supplying electricity. This is a normal policy activity for government. For example, it is akin to the policy of deductible interest on mortgages held by homeowners, which gives more money to those who choose to own a home rather than to rent one. The goal is to stimulate increased homeownership, and it works.

Once a decision has been made to intervene in the market, administratively, there are two fundamental alternatives on how to do so, as follows:

1) Administratively establish a desired quantity level (at 118%, for example). With this approach, the intervention takes the form of a

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[6] It might be acceptable in the electric industry of the future to have customers go unserved once the infrastructure of real-time prices and other demand-side response mechanisms are more fully developed and the system is able to ration supply via the voluntary decisions of the consumers not to consume. At the current time, however, with the paucity of demand-side response that exists in many parts of the country, the system is not yet able to rely on a fully voluntary rationing approach. See, for example, Alfred E. Kahn, "The Adequacy of Prospective Returns on Generation Investment under Price Control Mechanisms," The Electricity Journal, March 2002, pages 37 to 46.

[7] For a discussion of the relationship between capacity reserve requirements, energy market prices, and generation capacity payments, see Eric Hirst and Stan Hadley, "Maintaining Generation Adequacy in a Restructuring U.S. Electric Industry," ORNL/CON-472, Oak Ridge National Laboratory, October 1999, available at www.ehirst.com.

quantity target and the market is left to reveal the price adder that it needs in order to achieve that quantity target rather than the natural quantity that it would otherwise provide.

2) Administratively establish a price adder or a price adder formula. According to this approach, an added revenue stream is made available to all providers of capacity, the amount of that revenue stream is determined administratively, and the market is then left to reveal the amount of extra quantity it is willing to provide. (This is akin to the tax deduction on home mortgages that is provided to stimulate increased homeownership.)

In the northeast, we chose the first of the above two options. We established a 118% capacity requirement and are letting the marketplace reveal the price it needs to achieve this government-imposed target. For the remainder of this paper, we discuss the actual experience with this approach, note its fundamental shortcomings, and recommend a switch to an alternative that works along the lines of option 2) above.

Neither of the two intervention options is perfect, is effortless to calibrate, or allows one to avoid difficult decisions. In summary, the point of this section is that, once one has decided to reject the reliability level the market would naturally produce, and instead decides to intervene to alter that outcome, one will be faced with a challenge, will have to continually reassess the effectiveness of the intervention mechanism, and will need to make adjustments. There is no pure market-based way of intervening.

Current New York ICAP Market Rules

The current rules for the New York ICAP market require Load Serving Entities (LSEs) to buy generation capacity from generation owners to cover their forecasted peak load, plus an 18% margin. LSEs that fail to cover this margin pay a very large penalty. Sellers of ICAP receive the revenues associated with the ICAP market and, in return, obtain an obligation to bid into the NYISO's day-ahead energy market every day. Similar rules govern ICAP markets in the Pennsylvania, New Jersey, Maryland (PJM) ISO, and in ISO-NE (New England).

In theory, one would expect the New York ICAP rules to produce very high market prices when capacity is short and very low ICAP prices when the market is in surplus. This is because the market design puts no value on extra capacity beyond the peak 118% target, while placing a very high value on capacity whenever the system is even slightly short of the target. In practice, the market has lived up to this theory, and market clearing prices in New York have been quite volatile. There was one occasion in which the upstate ICAP market was short and cleared at the extremely high maximum value associated with the penalty, while more recently, given a roughly 5% excess (i.e., 23% reserves), the market has crashed to an exceedingly low value below $1.00/kW-month. Market participants often talk about the 118% reserve level as a cliff, and use the term "falling off the cliff" to represent what happens to price when reserves grow to exceed the target. Although the current 123% reserve margin within NYS does not seem excessive, it has nevertheless driven the market clearing price down dramatically and undervalues the benefit of the additional reserve margin.

From a generation owner's point of view, the New York ICAP market design is fatally flawed. It yields ICAP prices that are highly volatile and it exhibits an excessive tendency for prices to crash toward zero. From a banker or equity investor's point of view, investing in a new generation facility cannot be done with any significant reliance on the expectation of future ICAP revenues. The extreme volatility of ICAP revenues over time forces investors to heavily discount the ICAP revenue stream when performing financial analysis of the likely profitability of a new investment in generation. The result is that, although significant ICAP payments are made over time, the buying side of the market gets very little for such payments in terms of inducing additional entry.

From a buyer's point of view, the current New York ICAP market design raises another concern, and that is its extreme susceptibility to the exercise of market power. For any period in which the actual generation reserve is just slightly over 18%, a competitive market would yield a reasonable price that lies slightly below the annual fixed cost of a peaker. Yet, at such times, any one of the fairly large suppliers in the market would appear to be able to withhold a portion of its capacity and, in doing so, drive the market into a deficiency causing a dramatic jump in the ICAP price up to its maximum allowable level, which is three times the annual fixed cost of a peaker. This market power concern is magnified by the knowledge that the New York ISO's Market Monitoring Unit has no mitigation measures that apply to the ICAP market. So long as the market is reasonably flush, as is currently the case upstate, buyers do not have any immediate fears, with the possible exception of sudden retirements that might drive the ICAP market into a deficiency state. However, over time, as load growth causes the actual generation reserve to shrink back toward the 118% level, the potential for market power that can artificially drive up the price looms large.

Overall, therefore, the current New York ICAP market design is unsatisfactory to both buyers and sellers. It presents the prospect of a future in which ICAP prices are often low, but can't stay low and still have generators all stay in business. There will inevitably be periods in which the reserve margin shrinks, drops below 118%, and drives ICAP prices to their maximum, yielding short-term bonanzas for generators and nightmares for consumers. These would, in turn, be followed by periods in which new investment occurs yielding sufficient or excess capacity, accompanied by excessively low ICAP prices. Such a pattern of volatile prices, and volatile reliability, is not in anyone's interest.

<u>The NYPSC Staff's Proposed Resource Adequacy Assurance Mechanism</u>

In recent months, the NYPSC staff has proposed a different kind of mechanism called the Resource Adequacy Assurance Mechanism (RAAM).[8] It would replace the current ICAP market rules with a substantially different approach. The proposal is designed to achieve the following three goals:

1) Smooth out the pattern of capacity prices over time, i.e., reduce the market's price volatility, thereby giving greater assurance to potential new entrants and their bankers that they can count on capacity revenues in considering investments in new generation facilities.

2) Reduce the vulnerability of the capacity market to the exercise of market power by suppliers.

3) Foster a visible forward market in capacity supplies, with posted prices that are available to guide both small and large players alike in entering long-term capacity and/or energy contracts.

In the context of the earlier discussion of the two possible types of government intervention in the market, the RAAM is the second type, i.e., the intervention is in the form of a revenue enhancement whose goal is to boost the quantity of capacity above the level that the market would naturally produce.

The NYPSC staff proposal derives in part from an acknowledgement that the existing ICAP market design contains a willingness to pay for capacity that is schizophrenic; it insists on acquiring capacity right up to the 118% level (as expressed by the huge price per kilowatt during a deficiency), but then expresses absolutely no willingness to pay for any megawatts at capacity levels that are even slightly beyond 118%. This is a highly artificial construct that does not represent the true value to the electric system of one more or one less megawatt of capacity at or near the 118% target. An assumption behind the current mechanism is that, in equilibrium at 118%, the reliability value to the electric system of one MW of additional capacity equals the annual carrying costs of a combustion turbine. This feature is lost, however, by the mechanics of the proposal in which: 1) the penalty is set at three times the annual cost of a combustion turbine whenever capacity is even slightly short of 118%; and 2) the market clearing price is allowed to crash to a level dramatically below the annual carrying costs of a combustion turbine whenever capacity exceeds 118%.

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[8] It should be noted that, while the methodological aspects of the PSC staff proposal have been favorably received by a number of market participants, there are three or more variations being considered, each having different numerical values for the key parameters of the mechanism.

The RAAM attempts to more realistically represent the true value to the system of a little more or a little less capacity at or near the target level. The key to the proposal is a much smoother willingness to pay or "demand curve" for capacity. According to the RAAM, the system is willing to acquire more than 118% capacity reserves, albeit at somewhat lower prices than it will pay at a level equal to 118%. Similarly, when reserves fall short of 118%, the system will pay a price that is higher than the annual fixed costs of a peaker, but not nearly so high as the current mechanism's extremely large penalty.

Whereas the current New York ICAP market design is one in which the natural market is altered via the administrative establishment of a quantity target of 118%, and the market is left to determine the price, the NYPSC staff proposal is one in which a price for capacity is established, and the market is then left to reveal the quantity that it will supply at that price. The difficult part is to choose a price that will elicit the right quantity response, i.e., a capacity reserve in the appropriate range of 18% or slightly larger.[9] Rather than establish a single price and passively observe the quantity that results, the price adder the RAAM provides to the market is not fixed, but varies depending on the actual quantity of capacity offered. The price that is paid to capacity declines gradually as the quantity that emerges from the market exceeds the 118% goal; this automatically dampens the amount of quantity the market creates in the event that the price adder one has chosen is stimulating too much quantity. Conversely, if the quantity of capacity coming forth from the market falls short of the desired quantity goal of

[9] If a price is chosen that is too high, one can be saddled with a large amount of capacity that is not needed and which gets overpaid. New York and several other states have experienced this problem in the context of the Public Utilities Regulatory Policy Act (PURPA), in which an overstated estimate of avoided costs

around 118%, the price rises in an attempt to automatically bring forth more quantity.[10] If, over time, it becomes apparent that the overall schedule of prices inherent in the mechanism is too high or too low, the whole price schedule can be adjusted up or down to improve its ability to yield approximately the right amount of capacity. A detailed description of the NYPSC staff proposal is beyond the scope of this paper.[11]

A look at the features of the RAAM shows that it will greatly stabilize the spot market clearing price for generation capacity. At times of modest excess supply, the price will fall only slightly, rather than crash. This makes it much easier to forecast the likely future stream of capacity market prices. Not only will this be pleasing to generation entrants and their bankers, it will also help facilitate forward markets for capacity, since both buyers and sellers will feel they can reasonably predict the future spot market for capacity, which will give them confidence that the forward price they negotiate is within a reasonable range. As for market power, the slope of the demand curve for capacity in the RAAM has been specifically chosen to be gradual enough to ensure that even fairly large generation owners will be unable to profitably withhold supply.

Forward Markets for Generation Capacity (and Energy)

To foster the development of forward markets for generation capacity contracts, the NYPSC staff proposal could contain a requirement that all LSEs purchase 75% of their expected capacity needs three years ahead of time. This requirement forces

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led to overstated prices being offered for independent generation, which led to too much of it. If a price is chosen that is too low, an insufficient amount of capacity will result.

[10] Energy market prices will also rise if the quantity of capacity falls short of the desired level, further stimulating new capacity additions.

[11] For a detailed description, go to www.pjm.com, and look under Committees; Joint Capacity Adequacy Group; Agenda Items #4.

LSEs and generation suppliers to come together well ahead of time and attempt to make bilateral contracts with one another. Since only 75% of the market's generation will be required to be bought at the three-year-ahead of time point, it is highly unlikely that the three-year-ahead market could be gamed by generators through the exercise of market power. In essence, the three-year-ahead market has a 25% excess supply. Suppliers that are interested in locking in a price ahead of time will come to this market and will offer the generation capacity needed to satisfy the 75% requirements of the buyers. It would be expected that the prices in such a market would reflect both buyers and sellers forecasts of the future spot market that would prevail three years later.[12]

The combination of the more stable spot market for generation capacity created by the demand curve feature and the 75% forward purchase requirement will facilitate activity in forward markets. It is reasonable to expect that forward markets for the combined product of capacity and energy will also thrive. This would accomplish a key goal of policymakers.

Rate Impacts and the Need for a Phase-In

For upstate New York consumers, an immediate implementation of the RAAM presents an important problem. It would appear that the proposal would produce an immediate shift in capacity prices from the current market clearing price of about

[12] It should be noted that a forward market purchase requirement that would call on buyers to obtain 100% of their needs in advance could be highly subject to the exercise of market power by suppliers. The problem is that suppliers could withhold supply to drive up the three-year-ahead price knowing that any supply not sold at that time would still be available for sale in the spot market, and at a fair price. In normal commodity markets, such market power in forward markets is not possible, since buyers have the discretion of simply side stepping a high forward price by waiting until later to make the purchase. The problem with a 100% three-year-ahead buyers' requirement is that it would take away the discretion of buyers to defer purchases without taking the very same deferral option away from the selling side of the market, creating an asymmetrical and distorted three-year ahead of time market price. While this lack of symmetry is present in a 75% requirement, it has a very small likelihood of creating a market power problem given that the level of the requirement is just 75% and not 100%. Put in terminology recently

$1.00 per kW-month to a significantly higher level. The amount by which the existing price would be exceeded is difficult to predict and would depend in large part on the amount of imports that are drawn into New York by its willingness to pay for extra capacity. Even if the new approach yields prices in the $2 to $3 range, the immediate impacts on upstate consumers would be substantial. One reasonable way to address this concern is to phase in the RAAM. This can be accomplished by starting with a demand curve that is lower than the one to which the proposal eventually settles in at. Each year the demand curve could be raised until at the end of an appropriate phase-in period, three or four years, for example, the final proposal is fully in place.

From a generation entrant's point of view, a phase-in will work well, since any entity currently considering whether or not to enter would not have its plant built and on-line until three or four years hence. Existing generators should also welcome such a proposal, since it represents an increased revenue stream in each year relative to retention of the status quo, and will ultimately yield the full implementation of the RAAM, and all its beneficial features, within three to four years. In essence, the RAAM is seeking long-run benefits and the only thing necessary in the short run is to assure that there are no excessive short-run customer impact problems. A phase-in would appear to perform this job well.

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used by the FERC, there are no pivotal sellers in a market with a 75% requirement, whereas there are such sellers in a market with a 100% requirement.

ATTACHMENT 6

NEW YORK INDEPENDENT SYSTEM OPERATOR

290 Washington Avenue Extension, Albany, New York 12203

December 1, 2004

The Honorable Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Docket No. ER03-647-00

New York Independent System Operator, Inc.
Second Annual Compliance Report on Implementation of the ICAP Demand Curve
and Withholding Behavior Under the ICAP Demand Curve

Dear Ms. Salas:

Pursuant to Ordering Paragraphs (C) and (D) of the May 20, 2003, Order in Docket No. 03-647-000 (the "Initial Order"),[1] the New York Independent System Operator, Inc. ("NYISO"), by counsel, hereby submits this compliance report.

The report addresses, as of December 1, 2004: (i) the implementation and experience to date of the NYISO's Installed Capacity ("ICAP") Demand Curves; and (ii) the NYISO's evaluation of any withholding behavior by ICAP suppliers that may have occurred in the twelve-month period following the NYISO's prior report to the Commission.[2]

I. List of Documents Submitted

The NYISO submits the following documents:

1. This filing letter;

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[1] *New York Independent System Operator, Inc.*, 103 FERC ¶ 61,201 (2002).

[2] Capitalized terms not otherwise defined herein shall have the meaning set forth in Article 2 of the NYISO's Market Administration and Control Area Services Tariff.

2. a report on the implementation of and experience with the ICAP Demand Curves ("Attachment I"),

3. a report on the NYISO's evaluation of any withholding behavior by ICAP suppliers during the twelve-month period ending December 1, 2004 ("Attachment II"); and,

4. A form of *Federal Register* Notice ("Attachment III").

II. Copies of Correspondence

Copies of correspondence concerning this filing should be served on:

Robert E. Fernandez, General Counsel and Secretary
Elaine Robinson, Director of Regulatory Affairs
Gerald R. Deaver, Senior Attorney
New York Independent System Operator, Inc.
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III. Service List

The NYISO respectfully requests a waiver of the requirements of Rule 2010 so that it may use electronic service methods. The NYISO will electronically serve a copy of this filing on the official representative of each of its Market Participants, on each participant in its stakeholder governance committees, on the New York Public Service Commission, and on the New Jersey Board of Public Utilities. The NYISO will provide the Pennsylvania Public Utility Commission with a hard copy of this filing, as requested by that agency. The use of this procedure has been convenient for both the NYISO and for the recipients of this form of service, and to date, the procedure has engendered no complaints. Finally, allowing the use of electronic service would be consistent with the spirit of the Commission's recent Notice of Proposed Rulemaking regarding service and notification procedures.[3]

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[3] *Electronic Notification of Commission Issuances, Notice of Proposed rulemaking*, 107 FERC ¶ 61,311 (2004).

IV. Compliance Reports

A. Implementation and Experience To Date of ICAP Demand Curves

Implemented in May 2003 following the Initial Order, the ICAP Demand Curves have now been place for only eighteen months. In the relatively brief time since implementation of the Demand Curves, however, the NYISO has already observed the beginnings of trends in the ICAP markets that it anticipated and described in its original Demand Curve proposal to this Commission. A complete report is included herewith as Attachment I.

B. Withholding Behavior Under the ICAP Demand Curves

In its initial December 1, 2003 report to the Commission on ICAP withholding behavior, the NYISO indicated that it had not observed any significant economic or physical withholding of resources in the ICAP markets since the May 2003 implementation of the ICAP Demand Curves. Likewise, as of the date of this report, the NYISO continues to see no evidence of significant physical or economic withholding in the New York ICAP markets. A complete report of the NYISO's evaluation is included herewith as Attachment II.

V. *Federal Register* Notice

A form of *Federal Register* Notice is provided herewith. A diskette of the Notice is also provided in WordPerfect format.

Respectfully submitted,

s/s Gerald R. Deaver

____
Counsel for
New York Independent System Operator, Inc.

Robert E. Fernandez, General Counsel and Secretary
Gerald R. Deaver, Senior Attorney
New York Independent System Operator, Inc.
3890 Carman Road
Schenectady, NY 12303

cc: Daniel L. Larcamp, Director Office of Markets, Tariffs and Rates, Room 8A-01, Tel. (202) 502-6700
Anna Cochrane, Director Office of Markets, Tariffs and Rates -- East Division, Room 71-31, Tel. (202) 502-8284

Robert E. Pease, Director of Division of Enforcement, Office of Market Oversight and Enforcement, Room 9E-01, Tel. (202) 502-8131
Michael A. Bardee, Lead Counsel for Markets, Tariffs and Rates, Room 101-09, Tel. (202) 502-8068

ATTACHMENT I

New York Independent System Operator, Inc.
<u>December 1, 2004 Report on Implementation of the ICAP Demand Curve</u>

I. Executive Summary

Implemented in May 2003 following the Initial Order, the ICAP Demand Curves have now been in place for eighteen months.

In this relatively brief initial period of experience with the Demand Curves since implementation, the NYISO has already observed trends and behaviors in the ICAP markets that were anticipated as being among the benefits of the Demand Curves. As expected ICAP prices have become more stable. While not entirely attributable to the existence of the ICAP Demand Curves, the MW of capacity committed to the New York markets has trended upwards for the NYCA, as a whole, and for the New York City and Long Island localities, as well. The upward trend results from both new in-state capacity and increased imports from outside the control area.

With the increase of available capacity, ICAP prices have stabilized and are trending downward, which is an expected outcome for a competitive market with a current excess of supply. New York City and Long Island locational prices remain relatively stable, due in large part to the effects of price caps in New York City and the significantly bilateral nature of the Long Island market. The NYISO has observed no discernible increase in new bilateral arrangements; however, it has not observed any decrease in the bilateral segment of the New York markets, which is a further indication of a market evolution away from price volatility and towards price stability.

Finally, given the relatively brief history of the ICAP Demand Curves and the comparatively long lead time required to develop new generation, it is difficult to reach any specific conclusions regarding the effects of the Demand Curves on investment in new generation in New York. The reduced pace of new generation investment in New York reflects the current situation of excess capacity and current market clearing prices are correctly reflecting these market conditions.

II. Study of Implementation

In preparing this report, the NYISO's Market Services Department ("MSD") analyzed ICAP Market auction results from May 2003 through October 2004. This period encompasses the Summer 2003 Capability Period, the 2003-2004 Winter Capability Period, and the Summer 2004 Capability Period.

A. Installed Capacity Auction Results

Market clearing prices in the ICAP auctions have continued to show a trend towards stability since the implementation of the ICAP Demand Curves and the NYISO's December 1, 2003, initial report to the Commission. In addition, the amount of capacity purchased in the auctions has continued to increase, as was anticipated given the Demand Curves function of placing some value on capacity in excess of the Minimum ICAP Requirement. Capacity purchased in excess of the minimum reliability requirements equaled 3,465 MW for the NYCA as a whole, and 215 MW each for the New York City and Long Island load zones as of October 2004. A more detailed discussion of the purchases in the ICAP auctions is included in Section B, below.

Market clearing prices and auction activity levels, from the implementation of the ICAP Demand Curves through October 2004, are shown in Figures 1, 2, and 3, below, for Rest of State, New York City, and Long Island, respectively. Because ICAP purchase obligations and supplier certifications are translated into Unforced Capacity ("UCAP") terms for the auctions, the data presented in tables and graphs throughout this report are expressed in UCAP terms.

Figure 1
May 2003 – October 2004
Installed Capacity Auction Activity
New York Control Area (NYCA) Capacity

	Capability Period* (Strip)		**Monthly**		**ICAP Spot Market**	
Month	***MW***	***Price***	***MW***	***Price***	***MW***	***Price***
May-2003	2889.2	$1.67	1634.8	$1.30	101.5	$0.25
June-2003	2889.2	$1.67	1866.0	$1.06	2148.7	$2.34
July-2003	2889.2	$1.67	1249.2	$2.01	2824.2	$2.28
August-2003	2889.2	$1.67	1344.1	$2.04	3096.6	$2.25
September-2003	2889.2	$1.67	1396.7	$1.97	3134.1	$2.08
October-2003	2889.2	$1.67	1408.4	$1.93	3253.2	$2.01
November-2003	2163.2	$1.17	2128.8	$1.15	6833.0	$1.94
December-2003	2163.2	$1.17	1860.1	$1.48	7203.1	$1.79
January-2004	2163.2	$1.17	2083.6	$1.50	6972.2	$1.75
February-2004	2163.2	$1.17	2475.9	$1.58	6379.9	$1.73
March-2004	2163.2	$1.17	2180.0	$1.54	6569.8	$1.00
April-2004	2163.2	$1.17	2646.7	$0.99	6987.5	$0.80
May-2004	2441.0	$1.68	2489.7	$1.65	6189.1	$1.31
June-2004	2441.0	$1.68	2133.6	$1.48	6239.9	$1.27
July-2004	2441.0	$1.68	1756.7	$1.29	6410.6	$1.04
August-2004	2441.0	$1.68	2046.5	$1.15	6544.7	$1.17
September-2004	2441.0	$1.68	2258.8	$1.16	6456.2	$1.07
October-2004	2441.0	$1.68	2460.8	$1.18	6633.9	$1.12

*Capability Period awards are for a six-month periods:
May through October 2003 November 2003 – April 2004 May through October 2004

Figure 2
May
2003 –

October 2004
Installed Capacity Auction Activity
New York City Locality

New York City	Capability Period* (Strip)		Monthly		ICAP Spot Market	
Month	***MW***	***Price***	***MW***	***Price***	***MW***	***Price***
May-2003	2501.7	$11.22	3016.3	$10.00	110.2	$12.36
June-2003	2501.7	$11.22	683.0	$13.78	2375.5	$11.46
July-2003	2501.7	$11.22	527.9	$11.57	2558.0	$11.46
August-2003	2501.7	$11.22	567.9	$11.56	2497.9	$11.46
September-2003	2501.7	$11.22	558.1	$11.56	2499.5	$11.46
October-2003	2501.7	$11.22	638.8	$11.55	2415.1	$11.45
November-2003	475.0	$6.55	579.3	$6.67	5029.3	$6.98
December-2003	475.0	$6.55	909.4	$6.64	4711.0	$6.98
January-2004	475.0	$6.55	968.9	$6.64	4644.8	$6.98
February-2004	475.0	$6.55	2167.5	$6.77	3422.4	$6.98
March-2004	475.0	$6.55	1938.0	$6.05	3841.5	$6.98
April-2004	475.0	$6.55	2047.2	$6.00	3779.1	$6.98
May-2004	1245.3	$11.15	2022.4	$11.16	2898.3	$11.42
June-2004	1245.3	$11.15	2532.8	$11.29	2391.9	$11.42
July-2004	1245.3	$11.15	2705.7	$11.29	2261.3	$11.42
August-2004	1245.3	$11.15	3126.1	$11.25	1854.4	$11.42
September-2004	1245.3	$11.15	3272.4	$11.25	1798.6	$11.42
October-2004	1245.3	$11.15	2771.9	$11.21	2336.3	$11.42

*Capability Period awards are for a six-month periods:
May through October 2003 November 2003 – April 2004 May through October 2004

Figure 3
May 2003 – October 2004
Installed Capacity Auction Activity
Long Island Locality

Long Island	**Capability Period* (Strip)**		**Monthly**		**ICAP Spot Market**	
Month	***MW***	***Price***	***MW***	***Price***	***MW***	***Price***
May-2003	6.6	$9.41	2.2	$24.00	0.2	$23.00
June-2003	6.6	$9.41	0.0	--------	341.9	$5.17
July-2003	6.6	$9.41	1.0	$5.00	344.7	$5.14
August-2003	6.6	$9.41	1.1	$5.00	441.8	$4.03
September-2003	6.6	$9.41	0.0	--------	397.8	$4.55
October-2003	6.6	$9.41	0.0	--------	397.8	$4.55
November-2003	0	$4.00	0.0	--------	114.3	$8.14
December-2003	0	$4.00	0.0	--------	107.5	$8.22
January-2004	0	$4.00	0.0	--------	128.2	$7.99
February-2004	0	$4.00	0.6	$7.50	202.6	$7.08
March-2004	0	$4.00	0.6	$7.00	142.6	$7.72
April-2004	0	$4.00	0.6	$6.85	199.0	$7.04
May-2004	11.2	$8.00	1.6	$8.00	97.5	$9.83
June-2004	11.2	$8.00	11.2	$9.29	90.8	$9.79
July-2004	11.2	$8.00	15.9	$8.67	193.4	$8.42
August-2004	11.2	$8.00	16.4	$8.05	213.1	$8.16
September-2004	11.2	$8.00	16.2	$8.06	214.2	$8.15
October-2004	11.2	$8.00	16.2	$8.06	214.2	$8.15

*Capability Period awards are for a six-month periods:
May through October 2003 November 2003 – April 2004 May through October 2004

The market clearing prices reflected in the above figures are also depicted in graphic form in Figures 4, 5, and 6 below for the Rest of State, New York City, and Long Island, respectively.

Figure 4

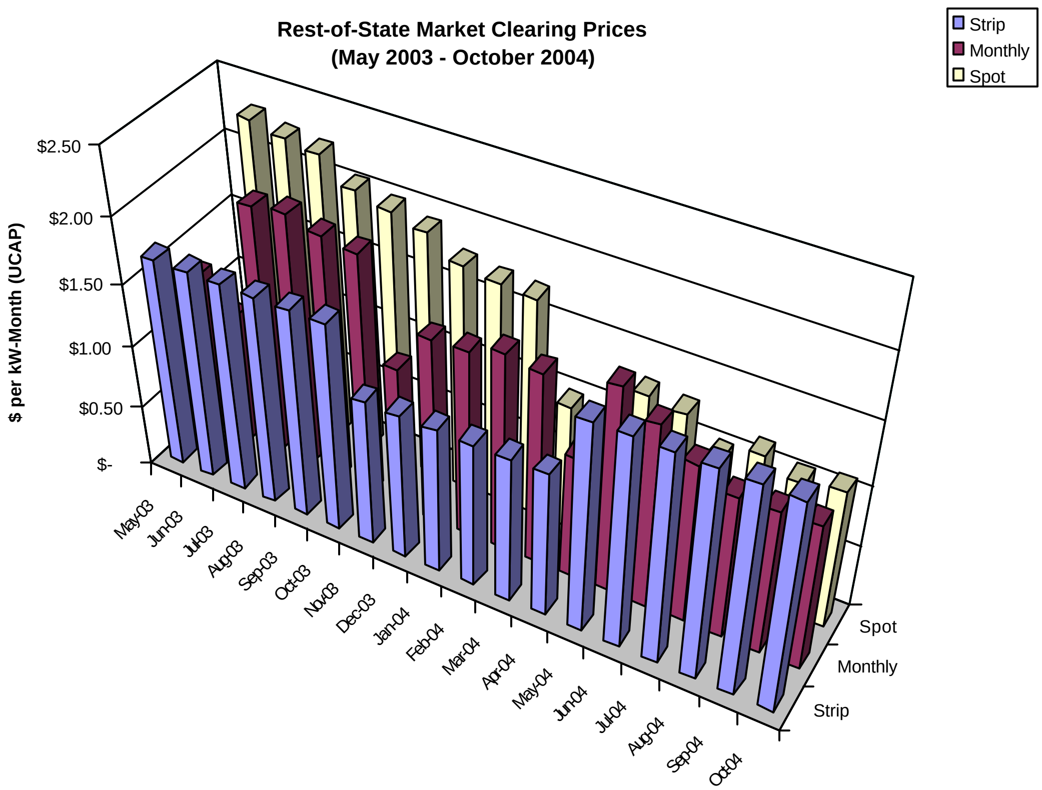


Figure 5

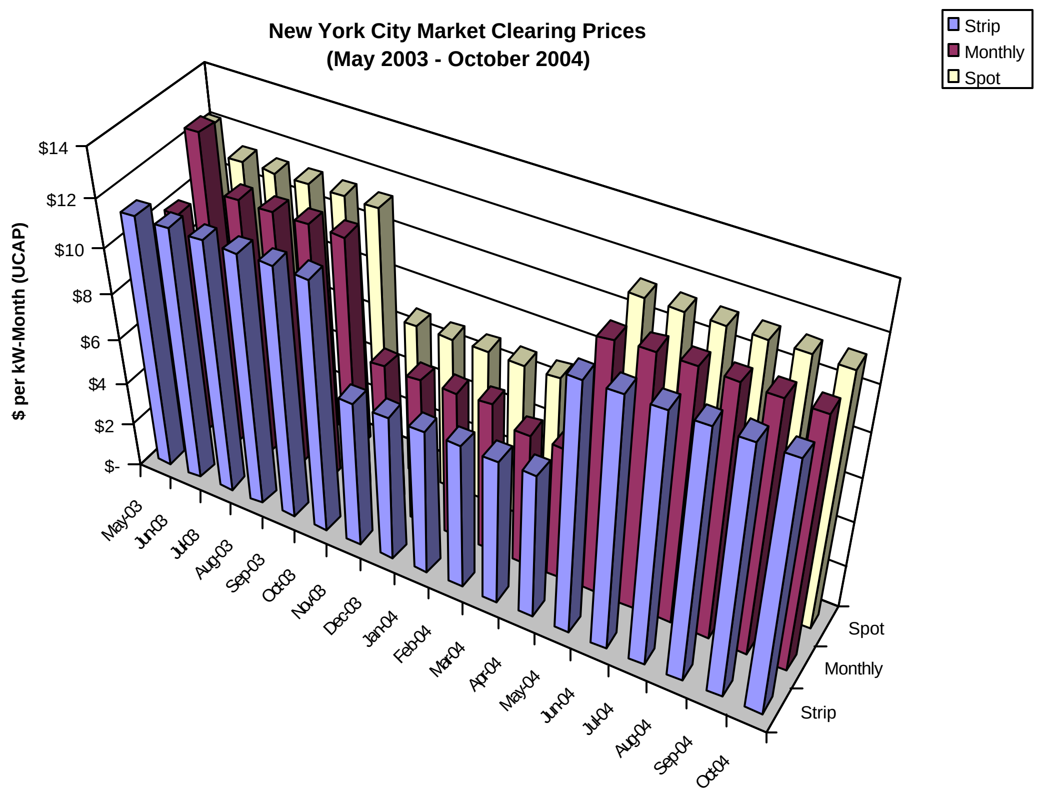
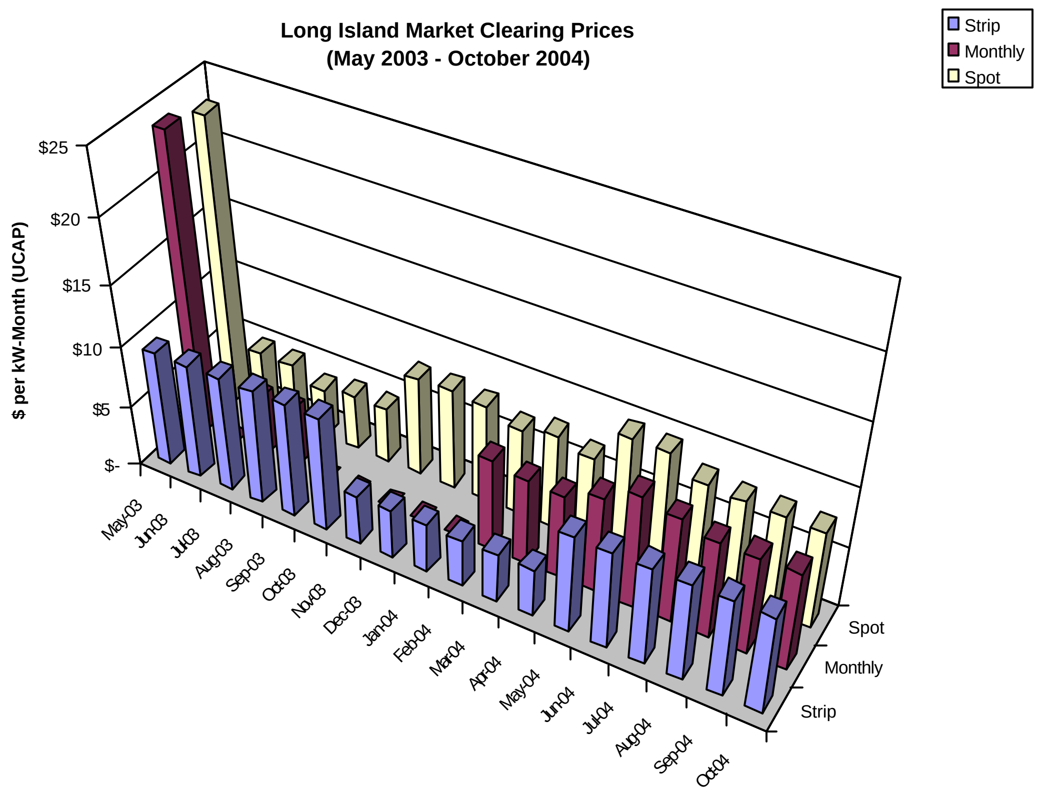

New York City Market Clearing Prices
(May 2003 - October 2004)
Strip
Monthly
Spot
$ per kW-Month (UCAP)
$14
$12
$10
$8
$6
$4
$2
$-
May-03
Jun-03
Jul-03
Aug-03
Sep-03
Oct-03
Nov-03
Dec-03
Jan-04
Feb-04
Mar-04
Apr-04
May-04
Jun-04
Jul-04
Aug-04
Sep-04
Oct-04
Spot
Monthly
Strip

Figure 6



B. Capacity Purchases

As previously reported to the Commission, the amount of capacity committed to the NYCA has continued to increase since the implementation of the ICAP Demand Curves. The NYISO also noted in its prior report that the amount of subscribed imports of external capacity had increased from 1,650 MW for the 2002 Summer Capability Period to 2,755 MW for the 2003 Summer Capability Period. This increased amount of subscribed import capability continued into the 2004 Summer Capability Period. Subscriptions for the Winter Capability Period increased from 900 MW for the 2002-2003 Winter Capability Period, which preceded the implementation of the Demand Curves, to 2,195 MW for the 2003-2004 Winter Capability Period.

The average amount of capacity committed each month in the ICAP market increased from 33,031 MW for the 2002 Summer Capability Period to 37,325 MW for the 2003 Summer Capability Period, and to 38,959 MW for the 2004 Summer Capability Period. The average capacity commitment increased from 34,293 MW in the 2002-2003 Winter Capability Period to 37,131 MW for the 2003-2004 Winter Capability Period. Further, Figures 7, 8, and 9 graphically demonstrate the minimum capacity obligations for the Rest of State, New York

City, and Long Island, respectively for the period since the Demand Curves were implemented.

Figure 7

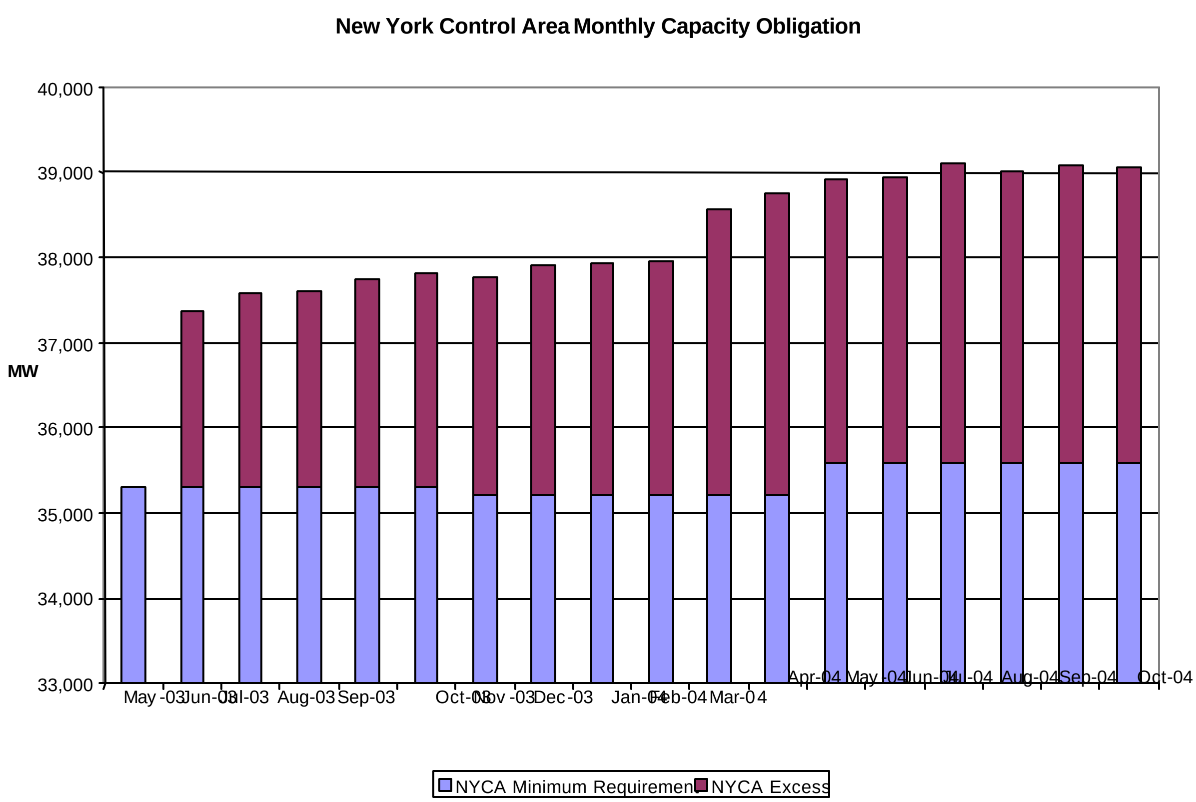


Figure 8

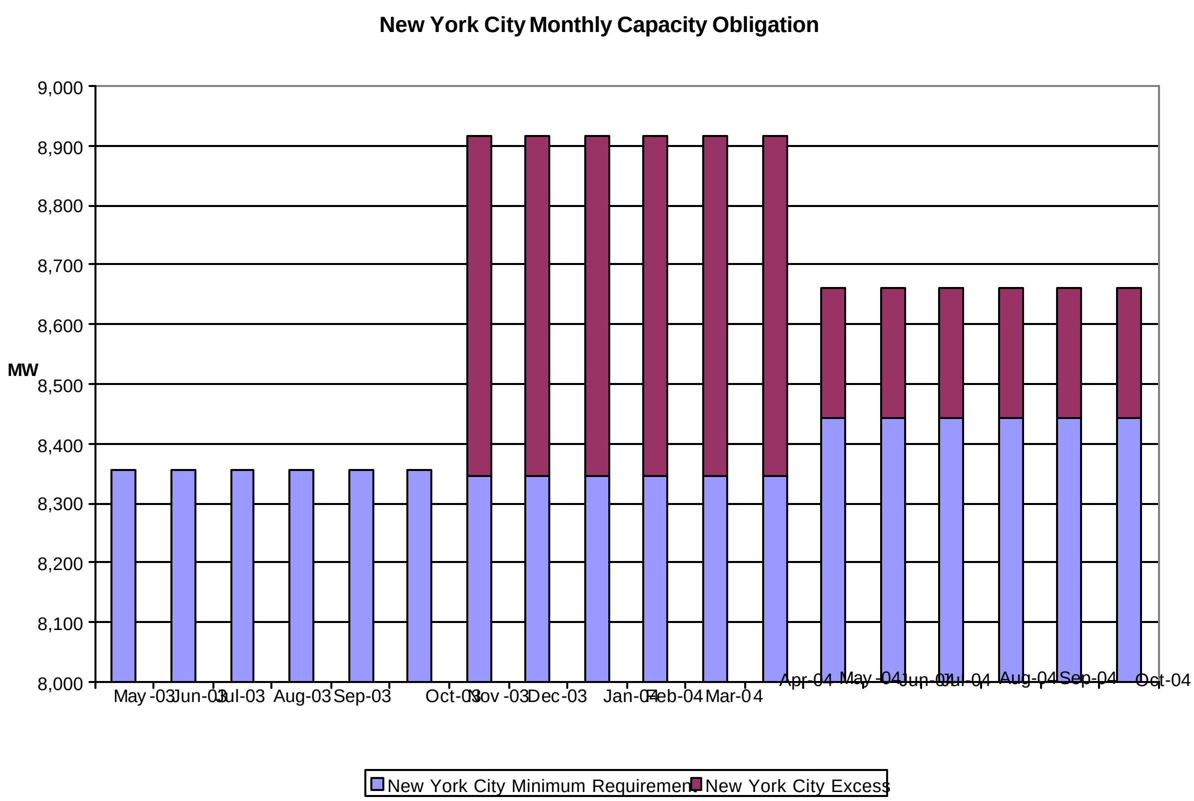
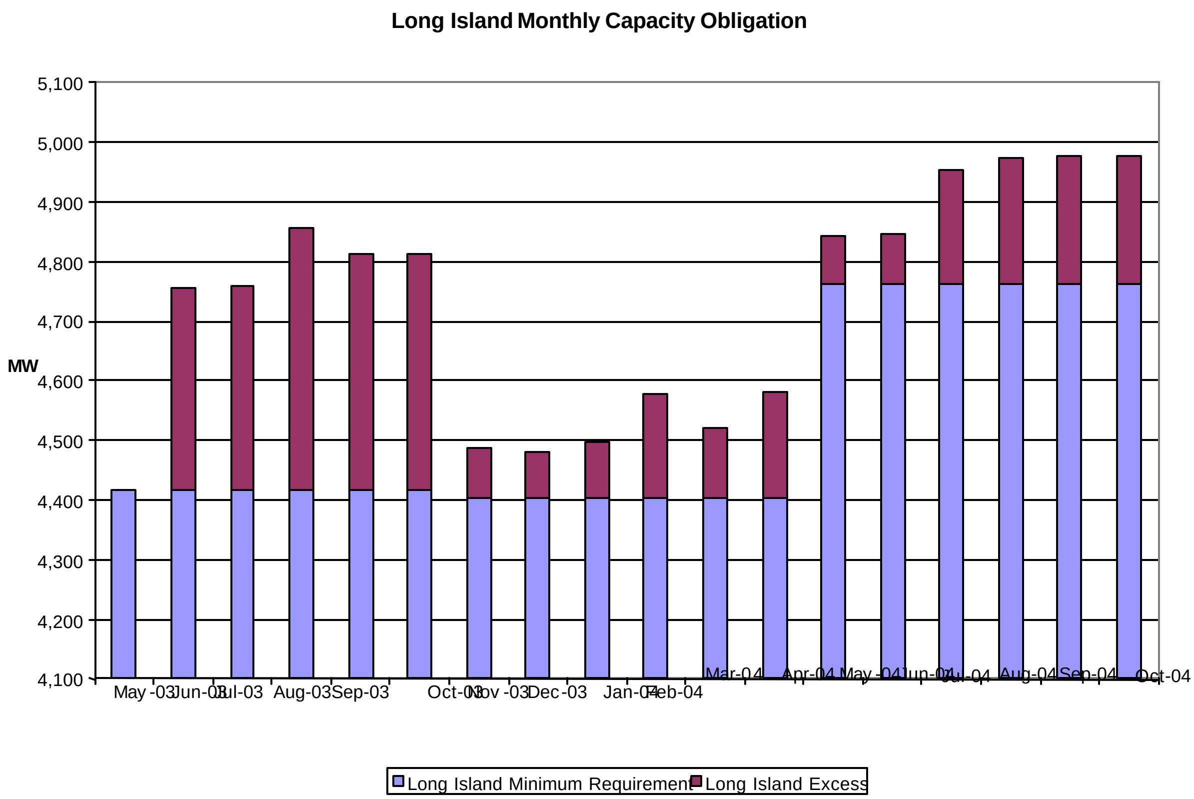

New York City Monthly Capacity Obligation
9,000
8,900
8,800
8,700
8,600
8,500
8,400
8,300
8,200
8,100
8,000
MW
May-03 Jun-03 Jul-03 Aug-03 Sep-03 Oct-03 Nov-03 Dec-03 Jan-04 Feb-04 Mar-04 Apr-04 May-04 Jun-04 Jul-04 Aug-04 Sep-04 Oct-04
New York City Minimum Requirement
New York City Excess

Figure 9



C. Unforced Capacity Requirements

In its prior report, the NYISO indicated that the minimum LSE Unforced Capacity requirement had increased by 2,824 MW from the 2002 Summer Capability Period to the 2003 Summer Capability Period. This increase was due primarily to a revised ICAP/ Unforced Capacity ("UCAP") translation methodology implemented by the NYISO in the Installed Capacity markets in November 2002, with the balance due to load growth. The current 2004 Capability Year Unforced Capacity requirements are 8,444.6 MW in New York City, 4,761.5 MW in Long Island and 35,684.5 MW for the NYCA.

III. Results of Study

A. Auction Behavior

The NYISO generally concludes that, as a result of the ICAP Demand Curves, the amount of capacity purchased in the Installed Capacity auctions has continued to increase since the implementation of Demand Curves, while ICAP market clearing prices have stabilized and are trending downward in response to current market conditions.

Prior to the implementation of the ICAP Demand Curves, Market Participants offered most of their capacity into the Capability Period and Monthly Auctions instead of the then-applicable monthly deficiency auctions. LSEs were required to purchase ICAP up to, but not in excess of, the their NYISO-established Minimum ICAP Requirement With the implementation of the ICAP Demand Curves, LSE UCAP purchase obligations are now determined and satisfied according to the monthly outcomes of the Spot Market Auctions under the Demand Curves. As a result, capacity suppliers have increasingly availed themselves of the ICAP Spot Market Auctions. The NYISO also notes that the ICAP Spot Market Auctions have continued to clear in MW amounts above the minimum UCAP requirements for New York City and Long Island.

B. Market Effects

The NYISO anticipated that the ICAP Demand Curves would result in price stability, an increase in the amount of capacity committed to Bilateral Transactions, and incentives to build new generation. In fact, the NYISO has observed an increase in capacity committed to the NYCA and an improvement in price signals.

Given the comparatively longer lead time required to site, develop, and complete the construction of a new generation project, it is difficult for the NYISO to demonstrate to the Commission any specific conclusions regarding the effects of the ICAP Demand Curves on development of new generation in the eighteen-month period since their implementation. Although the pace of new generation investment in New York has diminished somewhat, this result is more attributable to the current excess position in the ICAP markets and the lower market prices that accompany any supply situation in excess of demand.

It has always been the NYISO's expectation that the relative pace of new generation investment would reflect the degree of excess capacity present in the market at any given time. Because they place a value on, and provide some revenue for, capacity in excess of minimum reliability requirements, the NYISO continues to believe that the ICAP Demand Curves will provide price signals that encourage the addition of new generation in future increments that maintain system reliability. In the meantime, the present condition of excess capacity and the market clearing prices that result from such conditions correctly reflects a competitive ICAP market outcome. While it would be premature to reach specific conclusions after just eighteen months of experience with the ICAP Demand Curves, the NYISO is encouraged by its observation of market behaviors and outcomes that were anticipated for the Demand Curves. With the impending initial periodic adjustment of the

ICAP Demand Curve parameters, which will be submitted to the Commission for its approval in the near future, the NYISO anticipates that it should experience even more significant gains towards the objectives of the Demand Curves in the ICAP markets over the next three years.

The NYISO has consulted with the independent Market Advisor, Dr. David Patton, and he concurs in the conclusions in this report

ATTACHMENT II

New York Independent System Operator, Inc.
<u>December 1, 2004 Report on Withholding Behavior Under ICAP Demand Curves</u>

I. Executive Summary

In its initial December 1, 2003, report to the Commission on ICAP withholding, the NYISO indicated that it had not observed any significant economic or physical withholding of resources in the ICAP markets since the May 2003 implementation of the ICAP Demand Curves.

Likewise, as of the date of this report, the NYISO continues to see no evidence of significant physical or economic withholding in the New York ICAP markets. Bidding behaviors continue to support the conclusion that the clearing prices derived from the Demand Curves in the monthly Spot Market Auctions continue to be attractive to capacity suppliers and provide a venue for them to offer previously unsold capacity resources for the month. Within the NYCA, there is no category of ICAP in which apparent withholding exceeds six percent of available supplies. For most categories, including the locational ICAP markets for New York City and Long Island and the winter and summer Capability periods, apparent withholding percentages are much lower. In the summer capability period, for example, when available capacity supplies are at a minimum, almost every resource in the NYCA is offered into the ICAP auctions and sold. The level of capacity supplies that are not offered into the market amounts to less than one percent of statewide resources.

II. Study of Offering Behavior

A. Data

In developing the information for this report, the NYISO's Market Monitoring and Performance Department ("MMP") examined the same categories of data as were reviewed for the December 1, 2003, report to the Commission. Data from the 2003-2004 winter Capability Period (November 1, 2003 through April 30, 2004) and the 2004 summer Capability Period (May 1, 2004 through October 31, 2004) were reviewed for this report and included the following categories:

1. Certification data, which reflects the certified MW of Dependable Minimum Net Capacity for each generator seeking to supply ICAP. This represents the amount of capacity that a Market Participant has qualified to sell as ICAP each month, divided into MW committed to Bilateral Transactions, and MW offered into the ICAP auctions.

2. Installed Capacity requirements are established by the NYISO as the result of resource adequacy studies and the Installed Reserve Margin requirement determined by the New York State Reliability Council. The particular reference points on the ICAP Demand Curves, as utilized in the monthly Spot Market Auctions, are established in the NYISO tariffs.

3. Data for offers of capacity include the names of the offerors, the amount of capacity offered, the locality into which the capacity is offered, and any prices attached to those offers of capacity.

4. Auction outcome data include the amounts of capacity cleared in each auction, along with the price at which the capacity cleared. These data are arrayed by Market Participant, unit, locality, and specific auction, as necessary for MMP's analysis.

a. Analysis of Data Collected

The MMP analyzes withholding behavior in the New York resource adequacy markets in the context of the NYISO's ICAP market rules. For example, with the exception of the New York City locality, the NYISO tariff does not require capacity suppliers to offer into the ICAP markets. In the New York City load zone, the majority of capacity is subject to Commission-approved ICAP market mitigation measures that specifically require such capacity to be offered into the ICAP auctions to the extent that it has not been sold in a previous auction. A subset of New York City generation, principally capacity resources constructed subsequent to the Commission's approval of current tariff market mitigation provisions, is not subject to measures' mandate to offer into the auctions.

Other capacity inside and outside the NYCA may be sold bilaterally, or may be offered into one or more of the NYISO's ICAP auctions that take place for each six-month capability period. There are three types of auctions: a capability period (six-month strip) auction, six sets of monthly auctions, and six spot market auctions. Previously unsold capacity may be offered into any or all of the auctions.

The NYCA's minimum ICAP requirement is categorized into locational components: New York City, Long Island, and by subtraction, the Rest-of-State ("ROS"). Local reliability rules require LSEs in New York City and on Long Island to procure minimum percentages of capacity from facilities that are electrically located within their respective zones. The NYISO establishes locational ICAP requirements on an annual basis according to ISO Procedures. The following charts and tables in this report are disaggregated by zone to reflect these locational requirements.

Capacity sold by suppliers that are external to the NYCA is restricted to the simultaneous import capability of the transmission lines between the NYCA and neighboring control areas, which is currently approximately 2,755 MW. The MMP notes that capacity internal to the NYCA can also be offered to external control areas, consistent with their rules and the NYISO's rules governing such sales and transfers. The NYISO does not consider the offering of capacity from New York into another market to be presumptive evidence of withholding, so long as the behavior is economically rational.

The MMP notes further that it does not have a window into all of the options that may be available to external suppliers. For example, although external capacity may be qualified for the NYISO's ICAP markets pursuant to Section 5.12.1 of the Services Tariff, the owner may not have been able to obtain the necessary import rights over transmission ties to offer the capacity into the NYCA, in which case the external capacity does not qualify pursuant to Section 5.13.1 of the Services Tariff. Alternatively, the owner may choose to offer it somewhere else. Consequently, it is difficult to conclude that external suppliers are withholding supplies from New York, since the 2,755 MW limit is exceeded by the pool of otherwise available external capacity and a variety of other factors can influence the business decisions of external capacity owners.

III. Physical Withholding

With the above considerations provided as context, the MMP ascertains potential physical withholding by examining the amount of qualified capacity available, as compared to the amount sold bilaterally or offered into the auctions. Moreover, capacity can only be considered to be truly withheld only after it has not been made available in the last auction in the month(s) under consideration, which would be the monthly Spot Market auctions conducted by the NYISO pursuant to the ICAP Demand Curves.

Since the amounts of capacity available and offered can vary month to month, the MMP examines the capability periods in their entirety using monthly averages where appropriate for the monthly Capability Period and Spot Market auctions. The following Tables 1 and 2 summarize, in unforced capacity ("UCAP") terms, the "capacity available," "offered but not sold," and "not offered" for the winter 2003/2004 and summer 2004 capability periods. For markets such as New York's with no tariff requirement to offer capacity into the auctions, the term "physical withholding" has meaning only in very narrow circumstances. Such physical withholding would have to provide benefits to the remainder of an owner's portfolio through the consequence of higher auction clearing prices. Given the clearing prices shown in Tables 3 and 4 below, and the percentages certified but not offered, it is difficult for the MMP to conclude that a strategy of physical withholding by any capacity owner in the New York markets was even in place, or that such a strategy would be profitable on a small scale.

Table 1
Decomposition of Unsold UCAP: Winter Capability Period 2003 - 2004

	Monthly Average UCAP Available	*Monthly Average UCAP Sold in All Auctions or as Bilaterals*	*Monthly Average UCAP Not Offered*	*Monthly average UCAP Offered but not Sold*	*Percent of Available UCAP not Offered*	Percent of Available UCAP Offered but not Sold
NYCA Total	**45653.6**	**38378.1**	**7091.3**	**184.3**	**15.5%**	***0.4%***
Statewide	38281.6	36536.9	1586.7	157.9	4.14%	*0.4%*
ROS	24008.7	22595.9	1398.2	14.6	5.8%	*0.1%*
NYC	9123.6	8916.1	64.2	143.4	0.7%	*1.6%*
LI	5149.2	5024.9	124.3	0.0	2.4%	*0.0%*
PJM	3985.7	766.5	3219.2	0.0	80.8%	*0.0%*
HQ	800.0	238.6	535.1	26.3	66.9%	*3.3%*
NE	*2586.4*	*836.1*	*1750.3*	*0.0*	*67.7%*	*0.0%*

Table 2
Decomposition of Unsold UCAP: Summer Capability Period 2004

	Monthly Average UCAP Available	*Monthly Average UCAP Sold in All Auctions or as Bilaterals*	*Monthly Average UCAP Not Offered*	*Monthly average UCAP Offered but not Sold*	*Percent of Available UCAP not Offered*	Percent of Available UCAP Offered but not Sold
NYCA Total	**43914.4**	**39182.4**	**4626.9**	**105.0**	**10.5%**	***0.2%***
Statewide	37226.5	36719.1	402.4	105.0	1.1%	*0.3%*
ROS	23378.9	23051.3	324.4	3.1	1.4%	*0.01%*
NYC	8901.4	8739.5	61.2	100.7	0.7%	*1.1%*
LI	4946.2	4928.3	16.7	1.2	0.3%	*0.02%*
PJM	3980.5	852.5	3128.0	0.0	78.6%	*0.0%*
HQ	1200	735.3	464.7	0.0	38.7%	*0.0%*
NE	*1507.4*	*875.5*	*631.9*	*0.0*	*41.9%*	*0.0%*

(Numbers in the tables may not add up to the NYCA totals due to rounding.)

Tables 1 and 2 above disaggregate available UCAP into UCAP sales, UCAP Not Offered, and UCAP Offered but Not Sold. The seemingly high percentages of external UCAP not offered into New York result from transfer limits on import capability discussed above. Despite these transfer limits, over five percent of New York's UCAP was supplied from external control areas over the two capability periods. The MMP also notes that the total UCAP market was in a long position in both capability periods, as were the locational components. Excess capacity, however, is smallest in the summer and, in particular, on Long Island. Internal to the NYCA, the percentages of available UCAP not offered to the market are quite small; slightly over only four percent of supply is not offered in the winter, while approximately one percent is not offered in the summer. In New York City, where requirements to offer into the market are in effect for certain units but not others, physical withholding is less than one percent in both the winter and summer periods; approximately 60 MW were not offered, out of a total of approximately 9,000 MW of capacity actually available. Long Island exhibited seasonal variations, with 2.4% of available capacity not offered in the winter and 0.3% not offered in the summer.

IV. Economic Withholding

Economic withholding results when capacity supplies are purposefully bid into the ICAP markets at offer prices sufficiently above the subsequent clearing prices so as to not be taken in an auction. The MMP has examined the MWs of capacity involved in the New York markets, but not the offering prices of unsold capacity. The Demand Curves were originally intended to and, in fact, have significantly reduced the incentive to withhold generally. The Demand Curves accomplish this by increasing prices only gradually over the curves in response to physical withholding. Economic withholding of capacity into the NYISO's markets, if any, is quite small, estimated at 0.4% or 184 MW offered but not sold, out of 45,654 MW in the winter. The summer capability period exhibits even less economic withholding, 0.2% or 105 MW offered but not sold, out of 43,914 MW available.

Examining the MWs of capacity offered but not sold – as distinct from MWs not offered at all – can provide some insight into the determination of whether economic withholding may have occurred. For the New York City units subject to capacity mitigation and the requirement to bid, and on Long Island, where the 99% locational requirement coupled with the rights to virtually all of the existing capacity on the Island already secured, an implied offering requirement results. Under these circumstances, it is extremely difficult to conclude that a participant is offering in such a way as not to get taken in the locational auctions. Moreover, given the current long position of the ICAP markets in the Rest of State, the MMP cannot conclude that capacity owners are offering in such a way as to set auction clearing prices at anomalous levels or avoid being taken in the auctions altogether.

Long Island is an exception to the general conclusion, above, that there is no offering behavior in New York that leads to higher prices. Only a *de minimis* amount of capacity on Long Island is outside the control of the Long Island Power Authority ("LIPA"), the largest Market Participant in the load zone. LIPA's contractual right to most of the capacity on Long Island is pivotal. The few other Load Serving Entities on Long Island require certain amounts of capacity from LIPA in order to meet their locational ICAP obligations, and LIPA can control the amounts offered into the auctions and the prices at which those amounts are offered. Although there was no offered-but-unsold capacity on Long Island in the winter capability period and only a minuscule 1.2 MW of such capacity in the summer period, the auction clearing prices at which UCAP was transacted approached and sometimes exceeded New York City's capped load zone prices. While LIPA was not offering so as not to get taken in the auctions, it had the ability to control the clearing price.

In the Rest of State, only 0.1%, or 15 MW, was offered but not sold out of 24,009 MW available in the winter. In the summer, 3 MW were economically withheld out of 23,379 MW of capacity available. New York City experienced the highest proportion of capacity offered but not sold, which was still only 1.6% in the winter and 1.1% in the summer. While it may be assumed that price mitigated capacity is offered at the associated caps, unmitigated capacity is not so constrained. The auction data for New York City reveals that a portion of non-mitigated capacity was offered at prices above the caps that apply to some other units in the City.

V. Distribution of ICAP Sales Among the Auctions and Bilateral Arrangements

The MMP has also analyzed ICAP sales as allocated among the various opportunities for such transactions in the New York markets. ICAP is sold in New York in four different manners: as a bilateral transaction (which includes self-supply), and in the NYISO's six-month strip auctions, regular monthly auctions, and monthly Spot Market auctions. While it is premature to reach conclusions about market trends with only two summer capability periods and one winter period having been completed since the implementation of the Demand Curves, Table 3 provides some insight into offering behavior.

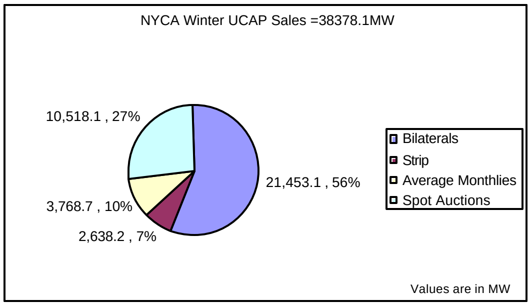
Table 3
UCAP Sales and Prices for the Winter 2003/2004 Capability Period

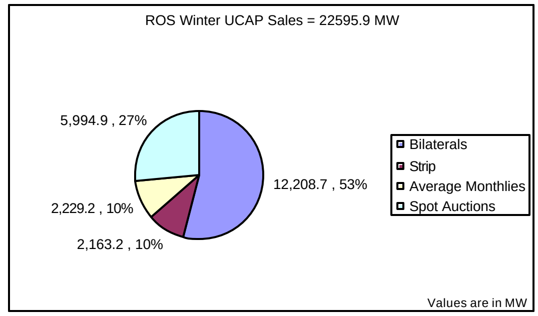
New York City	Capability Period (Strip)*		Monthly		UCAP Spot Market		Bilateral Transactions	UCAP Sold	UCAP Available
Month	***MW***	***Price*****	***MW***	***Price******	***MW***	***Price***	***MW***	***MW***	***MW***
November '03	475.0	$6.55	579.3	$6.67	5029.3	$6.98	2831.8	8,915.4	9100.1
December '03	475.0	$6.55	909.4	$6.64	4711.0	$6.98	2821.5	8,916.9	9114.1
January '04	475.0	$6.55	968.9	$6.64	4644.8	$6.98	2827.5	8,916.2	9124.9
February '04	475.0	$6.55	2167.5	$6.77	3422.4	$6.98	2851.0	8,915.9	9126.1
March '04	475.0	$6.55	1938.0	$6.05	3841.5	$6.98	2661.7	8,916.2	9134.3
April '04	475.0	$6.55	2047.2	$6.00	3779.1	$6.98	2614.5	8,915.8	9142.3
Long Island	**Capability Period (Strip)***		**Monthly**		**UCAP Spot Market**		**Bilateral Transactions**	**UCAP Sold**	**UCAP Available**
Month	***MW***	***Price*****	***MW***	***Price******	***MW***	***Price***	***MW***	***MW***	***MW***
November '03	0.0	$4.00	0.0	$4.00	114.3	$8.14	4896.4	5,010.7	5138.2
December '03	0.0	$4.00	0.0	-	107.5	$8.22	4911.4	5,018.9	5138.2
January '04	0.0	$4.00	0.0	-	128.2	$7.99	4891.4	5,019.6	5139.1
February '04	0.0	$4.00	0.6	$7.50	202.6	$7.08	4821.0	5,024.2	5143.7
March '04	0.0	$4.00	0.6	$7.00	142.6	$7.72	4881.7	5,024.9	5145.8
April '04	0.0	$4.00	0.6	$6.85	199.0	$7.04	4851.7	5,051.3	5190.2
Rest of State	**Capability Period (Strip)***		**Monthly**		**UCAP Spot Market**		**Bilateral Transactions**	**UCAP Sold**	**UCAP Available**
Month	***MW***	***Price*****	***MW***	***Price******	***MW***	***Price***	***MW***	***MW***	***MW***
November '03	2163.2	$1.667	2128.8	$1.15	6178.3	$1.94	13680.6	24,150.9	31294.1
December '03	2163.2	$1.667	1860.1	$1.48	6555.2	$1.78	13608.9	24,187.4	31318.0
January '04	2163.2	$1.667	2083.6	$1.50	6304.2	$1.75	13667.6	24,218.6	31399.3
February '04	2163.2	$1.667	2475.9	$1.58	5632.9	$1.73	13957.3	24,229.3	31421.4
March '04	2163.2	$1.667	2780.0	$1.54	5878.9	$1.00	14028.1	24,850.2	31421.4
April '04	2163.2	$1.667	2671.7	$0.99	6236.8	$0.80	13914.2	24,985.9	31430.5
NYCA	**Capability Period (Strip)***		**Monthly**		**UCAP Spot Market**		**Bilateral Transactions**	**UCAP Sold**	**UCAP Available**
Month	***MW***	***Price***	***MW***	***Price***	***MW***	***Price***	***MW***	***MW***	***MW***
November '03	2638.2		2708.1		11321.9		21408.8	38077.0	45532.4
December '03	2638.2		2769.5		11373.7		21341.8	38123.2	45570.3
January '04	2638.2		3052.5		11077.2		21386.5	38154.4	45663.3
February '04	2638.2		4644.0		9257.9		21629.3	38169.4	45691.2
March '04	2638.2		4718.6		9863.0		21571.5	38791.3	45701.5
April '04	2638.2		4719.5		10214.9		21380.4	38953.0	45763.0

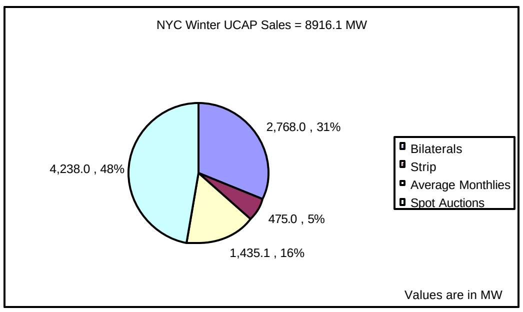
* Capability Period awards are for six-month periods:
November '03 through April '04 NYC = 2850.0 MW, LI = 0.0, ROS = 12,979.2 (In this chart ROS generally includes externals.)
** Capability or strip prices are determined on a kw/capability period basis:
NYC = $39.30, LI = $24.00, ROS = $7.00 the monthly numbers in the table are for convenience.
*** Weighted average price of all of the ICAP sales in the monthly auctions designated for that month.

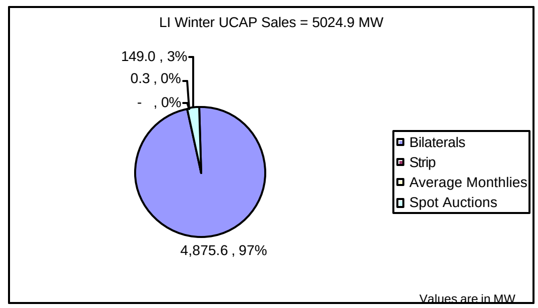
The winter period MW amounts and prices for the NYCA do not demonstrate an obvious trend across the months. A large jump in monthly sales occurred in the second half of the winter period from approximately 3,000 MW to 4,700 MW was offset by a drop in Spot Market sales. Two-thirds of this increase was attributable to a jump in monthly sales in New York City, with one-third of the increase resulting from Rest of State sales. Bilateral sales showed no trend, while Spot Market Auction sales showed a slight downward shift in New York City.

The following pie charts aggregate the details of monthly MW shown in the Table 3 above.









Approximately 56% of all NYCA UCAP sales take place through bilateral transactions in the winter period, while just over 27% of capacity is sold in the Spot Market Auctions. The remaining 17% is sold in the strip and regular monthly auctions. For the two localities, the allocation among markets is quite different. While the Rest of State results largely track the NYCA, 97% of Long Island UCAP is sold through bilateral transactions, with the remaining 3% sold in the Spot Market Auctions. Bilateral transactions account for 31% of New York City UCAP sales, while the Spot Market Auctions account for 48% of sales. The strip and monthly auctions account for the balance of UCAP transactions; approximately 20% in New York City and the Rest of State, but very nearly zero on Long Island.

Table 4
UCAP Sales and Prices for the Summer 2004 Capability Period

New York City	Capability Period (Strip)*		Monthly		UCAP Spot Market		Bilateral Transactions	UCAP Sold	UCAP Available
Month	***MW***	***Price*****	***MW***	***Price******	***MW***	***Price***	***MW***	***MW***	***MW***
May '04	1245.3	$11.15	2022.4	$11.16	2898.3	$11.42	2573.1	8,739.1	8,876.3
June '04	1245.3	$11.15	2532.8	$11.29	2391.9	$11.42	2569.6	8,739.6	8,882.4
July '04	1245.3	$11.15	2705.7	$11.29	2261.3	$11.42	2527.1	8,739.4	8,897.8
August '04	1245.3	$11.15	3126.1	$11.25	1854.4	$11.42	2513.4	8,739.2	8,907.4
September '04	1245.3	$11.15	3272.4	$11.25	1798.6	$11.42	2423.5	8,739.8	8,920.0
October '04	1245.3	$11.15	2771.9	$11.21	2336.3	$11.42	2386.5	8,740.0	8,924.7

Long Island	Capability Period (Strip)*		Monthly		UCAP Spot Market		Bilateral Transactions	UCAP Sold	UCAP Available
Month	***MW***	***Price*****	***MW***	***Price******	***MW***	***Price***	***MW***	***MW***	***MW***
May '04	11.2	$8.00	1.6	$8.00	97.5	$9.83	4732.6	4,842.9	4,846.1
June '04	11.2	$8.00	11.2	$9.29	90.8	$9.79	4732.8	4,846.0	4,927.1
July '04	11.2	$8.00	15.9	$8.67	193.4	$8.42	4734.1	4,954.6	4,965.3
August '04	11.2	$8.00	16.4	$8.05	213.1	$8.16	4734.0	4,974.7	4,978.9
September '04	11.2	$8.00	16.2	$8.06	214.2	$8.15	4734.2	4,975.8	4,979.9
October '04	11.2	$8.00	16.2	$8.06	214.2	$8.15	4734.2	4,975.8	4,979.9

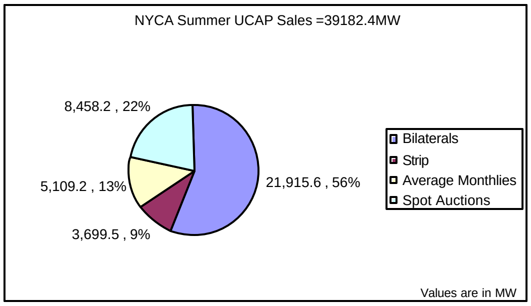
Rest of State	Capability Period (Strip)*		Monthly		UCAP Spot Market		Bilateral Transactions	UCAP Sold	UCAP Available
Month	***MW***	***Price*****	***MW***	***Price******	***MW***	***Price***	***MW***	***MW***	***MW***
May '04	2443.0	$1.680	2656.4	$1.65	5893.0	$1.31	14679.8	25,672.2	30,043.7
June '04	2443.0	$1.680	2300.3	$1.48	5940.7	$1.27	14802.9	25,486.9	30,046.7
July '04	2443.0	$1.680	1923.4	$1.29	6002.8	$1.04	15164.8	25,534.0	30,065.6
August '04	2443.0	$1.680	2213.2	$1.15	6116.7	$1.17	14651.3	25,424.2	30,086.6
September '04	2443.0	$1.680	2425.5	$1.16	6027.1	$1.07	14614.1	25,509.7	30,089.5
October '04	2443.0	$1.680	2627.5	$1.18	6204.8	$1.12	14185.5	25,460.8	30,068.4

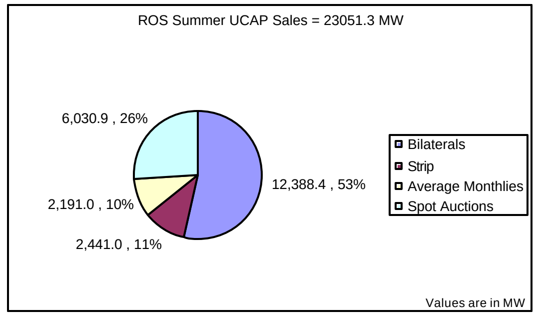
NYCA	Capability Period (Strip)*		Monthly		UCAP Spot Market		Bilateral Transactions	UCAP Sold	UCAP Available
Month	***MW***	***Price***	***MW***	***Price***	***MW***	***Price***	***MW***	***MW***	***MW***
May '04	3699.5		4680.4		8888.8		21985.5	39254.2	43766.1
June '04	3699.5		4844.3		8423.4		22105.3	39072.5	43856.2
July '04	3699.5		4645.0		8457.5		22426.0	39228.0	43928.7
August '04	3699.5		5355.7		8184.2		21898.7	39138.1	43972.9
September '04	3699.5		5714.1		8039.9		21771.8	39225.3	43989.4
October '04	3699.5		5415.6		8755.3		21306.2	39176.6	43973.0

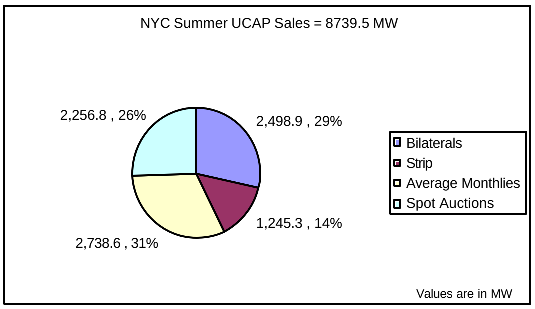
* Capability Period awards are for six-month periods:
May '04 through October '04 NYC = 7471.8 MW, LI = 67.2, ROS = 14658.0 (In this table ROS generally includes externals.)
** Capability or strip prices are determined on a kw/capability period basis:
NYC = $66.90, LI = $48.00, ROS = $10.08, HQ = $6.00. The monthly numbers in the table are for convenience.
*** Weighted average price of all of the ICAP sales in the monthly auctions designated for that month.

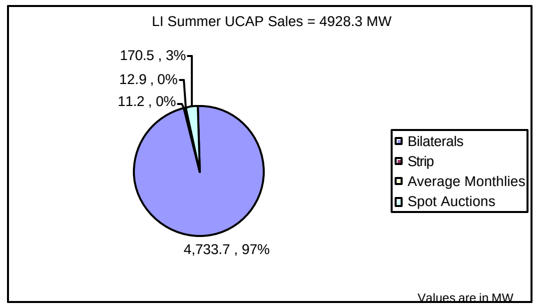
Summer period NYCA-wide monthly trends are similar to those in the winter. New York City experienced a jump of approximately 400 to 500 MW in monthly sales in the second half of the summer period. The Rest of State saw a similar jump in monthly sales. New York City also experienced a 400 MW decline in Spot Market Auction sales, while the Rest of State Spot Market sales have only slightly increased. Long Island experienced an increase of 120 MW in the second half of the summer period, as compared to the first half, but that change brought Long Island to a Spot Market sales level just above where it had been in the prior winter period.

The following pie charts aggregate the monthly MW detail shown in Table 4 above.









The summer NYCA-wide ratio between Spot Market Auctions and bilateral transactions does not differ significantly from the winter capability period. The Spot Market accounts for 22% of UCAP sales, while bilateral sales comprise almost 56%. Long Island continues the winter pattern, with Spot Market sales at 3% and bilateral sales at 97%. In New York City, UCAP sales are split more evenly among the markets, with bilateral sales making up approximately 29%, Spot Market sales equaling 26%, monthly auction sales accounting for 31%, and six-month strip auction sales equaling approximately 14%.

VI. Conclusions

The ICAP markets provide a variety of opportunities for Load Serving Entities and capacity suppliers to manage their respective and various levels of risk aversion. The lack of evidence of systemic physical or economic withholding should assure Market Participants and the Commission that the outcomes of the ICAP auctions are as fair and competitive as possible in the context of certain locational constraints.

Access to bilateral transactions allows more risk-averse Market Participants, whether Load Serving Entities or capacity suppliers, to manage their risk exposures within tolerable levels. The monthly Spot Market Auctions under the Demand Curves have provided opportunities to sell previously unsold ICAP and fulfill any remaining ICAP obligations at prices that are disciplined by the market. Vigorous strip and monthly auctions in the Rest of State for both capability periods, and for New York City in the summer capability period, provided opportunities to purchase or sell larger amounts of ICAP at reasonable prices for both purchasers and sellers.

Participation in the strip and monthly capability period auctions and in bilateral arrangements, however, is affected to some extent by the presence of the monthly Spot Market Auction. While future results under the published Demand Curves utilized in the Spot Market Auctions serves to inform buyers of the consequences of not procuring as much of their needs as possible in advance, the Demand Curves also serve to inform sellers of the consequences of waiting until the Spot Market Auction to sell their capacity. The fact that there is very little systemic withholding, and that there is a good mix of UCAP activity at all stages of the process and in all market categories, however, is a good indicator that the signals in the auctions are very clear and are working as intended.

The NYISO has consulted with the independent Market Advisor, Dr. David Patton, and he concurs in the conclusions in this report

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person that has executed a Service Agreement under the NYISO's Open Access Transmission Tariff or Market Administration and Control Area Services Tariff, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010 (20001).

Dated at Washington, D.C. this 1st day of December, 2004.

____

Gerald R. Deaver
Senior Attorney
New York Independent System Operator, Inc.
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518-356-7549

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc.) Docket No. ER03-647-00_

NOTICE OF FILING

Take notice that on December 1, 2004, the New York Independent System Operator, Inc. ("NYISO") submitted a second annual report on (i) the implementation of the ICAP Demand Curves, and, (ii) withholding behavior under the ICAP Demand Curves in compliance with the Commission's previous order in the above-captioned proceeding. The NYISO has served a copy of this filing upon all parties that have executed service agreements under the NYISO's Open Access Transmission Tariff and Market Administration and Control Area Services Tariff.

Copies of this filing have been served on all parties listed on the official service list in the above-captioned proceeding. The NYISO has also served a copy of this filing to all parties that have executed Service Agreements under the NYISO's Open-Access Transmission Tariff or Services Tariff, the New York State Public Service Commission, and to the electric utility regulatory agencies in New Jersey and Pennsylvania.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Magalie R. Salas
Secretary