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PUBLIC SERVICE COMMISSION

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March 7, 2003

Richard J. Grossi
Chairman
New York Independent System Operator
3890 Carman Road
Schenectady, New York 12303

c/o William J. Museler
President and Chief Executive Officer
New York Independent System Operator
3890 Carman Road
Schenectady, New York 12303

Re: Motion in Opposition to Appeals of the Management Committee's Decision

Dear Chairman Grossi and Mr. Museler:

Pursuant to sections 4.01 and 5.01 of the Procedural Rules for Appeals to the ISO Board, the New York Public Service Commission (NYPSC) respectfully submits three copies of its Motion in Opposition to the substantive appeals of the Management Committee's decision at its February 13, 2003 meeting regarding the demand curve. This motion has been electronically transmitted to NYISO Staff for purposes of service.

Attached are two documents that explain the key reasons that the PSC staff supports the Demand Curve approach to resource adequacy and why we continue to support it in the face of arguments from parties that are opposed to it. Appendix A is testimony on the Demand Curve approach given by PSC staff at the March 6, 2003 hearing of the Assembly Standing Committee on Energy. It briefly describes the concerns with the existing capacity market rules (pp. 3-5); the demand curve approach itself and how it resolves those concerns (pp. 6-8); the estimated near-term consumer impacts of the proposal (pp. 8-9); and responses to arguments in opposition to the proposal (pp. 9-13).

Appendix B was part of the NYPSC's filing regarding resource adequacy issues in the Federal Energy Regulatory Commission's Standard Electric Market Design proceeding (Docket No. RM01-12-000), dated January 31, 2003. It provides a much more detailed description of the Demand Curve approach itself, and its likely outcome, should the Board desire a more in-depth understanding of the concept.

Sincerely,

Saul A. Rigberg
Assistant Counsel

Attachments

APPENDIX A

Assembly Standing Committee
on Energy

Regarding a Proposal by the
New York Independent System Operator
Concerning Electricity Capacity Pricing

March 6, 2003

Prepared Testimony of:

Raj Addepalli, Ph.D., CFA
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PART I: Introduction and Process

Good Morning, Chairman Tonko and members of the Committee. Thank you for inviting us to offer our views on the proposed changes to the Installed Capacity Market administered by the New York Independent System Operator (NYISO). I will lay out our role in this effort and the process we used in arriving at the proposed solution. Then, my colleague Mark Reeder will explain the theory behind the proposed changes. After that, Harvey Arnett will present estimates of the costs of the proposal, and finally, I will summarize our views about the arguments opposing the Demand Curve.

As you know, the Public Service Commission is charged with the responsibility of ensuring that rates to consumers are “just and reasonable,” and the service is “safe and adequate.” Consumers’ bills for power consist primarily of two components, the cost of supply and the cost of delivery. The cost of supply for a utility’s portfolio, or for that matter, for the portfolio of any Load Serving Entity (LSE), typically consists of the cost of any “bilateral” agreements or contracts with suppliers, purchases in the wholesale market, and financial hedges. For the most part, the cost of supply to an LSE is influenced by the wholesale prices at the NYISO.

The NYISO tariffs are approved by the Federal Energy Regulatory Commission (FERC). Given the importance of wholesale power costs in a customer bill, the PSC plays an active role in monitoring the development of NYISO policies and at times proactively proposes changes to the NYISO's market rules. Our primary motivation in doing so is to ensure continued reliability of supply and fair pricing for consumers and suppliers. In addition, we are also concerned about market rules and practices that can lead to exercise of market power by generators to the detriment of consumers.

In keeping with our goals, last year we proposed changes to the capacity market when we noticed that the current market design was leading to results that could affect the long-term reliability of the system, and thus harm consumer welfare. Our proposed changes are expected to correct the flaws in the existing market and enhance consumer welfare by increasing reliability and lowering prices in the long run.

We discussed our proposal, a "Demand Curve" for the capacity market, with various market participants over the last year both informally and formally through the working group meetings at the NYISO. In December, the NYISO proposed a version of the Demand Curve for vote at the Business Issues Committee (BIC) meeting. The PSC was opposed to that proposal, as it did not provide some of the key protections that we believed were essential. The proposal was defeated by the market participants at the BIC meeting. The outcome was the same at the Management

Committee (MC) meeting in January. Staff worked with representatives of the generators to amend the problems with the NYISO proposal. During the process, we were cognizant of the concerns expressed by some of the opponents of the Demand Curve, and we attempted to address those issues as much as we could in developing a revised Demand Curve. We believe the revised Demand Curve proposal currently before the NYISO Board is fair and support its adoption.

Mr. Reeder will explain the rationale for the Demand Curve, and then Mr. Arnett will present the estimated impacts of the Demand Curve, and finally, I will respond to the criticisms raised by certain market participants.

PART II: Need and Purpose for DC and benefits

At the outset of the move to competitive wholesale electric markets, policy makers decided to retain the administrative rules governing generation adequacy to ensure that the existing level of reliability would be maintained. An alternative choice could have been to end such rules and allow the market the freedom to seek its own natural reliability level. This option was rejected largely because of the determination that we require a highly reliable electric system, and that it was too great a risk at that embryonic stage of the transition toward competition to turn such an important feature of the electric industry over to the marketplace.

The existing capacity market rules represent the way in which it was decided that the reliability standards would be accomplished as part of a market-based system. Each Load Serving Entity is required to acquire the rights to an amount of installed generation capacity that equals the LSE's load at the time of the electric system's peak plus an 18 percent reserve. LSEs that fail to do so are subject to a large financial penalty.

In theory, this type of rule will produce extremely high capacity market prices during a year when generating capacity levels are short of the 18 percent reserve. Conversely, it will produce extremely low prices in a year in which the system has excess generating capacity.

In practice, this pattern has emerged. Prices were very high upstate for the only month in which a capacity shortage occurred, and have been very low for most of the months in which an excess has existed. While it is normal for prices to move up and down with changes in supply and demand, in the existing capacity market, even changes as small as five percent of available capacity can produce dramatic swings; a price spike or a price that crashes to near-zero levels.

This boom or bust feature harms consumers both directly and indirectly. The direct harm happens via the price spikes that occur during a deficiency. Furthermore, the high degree of sensitivity of the market's price to supply changes makes the market vulnerable to price spikes caused by supplier market power. Whenever the electric system has enough capacity, but only barely enough, a large supplier can withhold some of its supply from the market and induce an artificial capacity shortage and its concomitant price spike. The exposure of consumers to such price spikes is a continuing concern about the existing market design.

The indirect harm that can befall consumers from the existing capacity market design is a long-run concern that the monies that flow from the capacity market to generators over time will be characterized by such a large degree of volatility that they will count for little in the financial calculus of potential new developers. If suppliers of investment capital heavily discount these volatile capacity payments, consumers will end up paying a lot of money over time, but getting little benefit from their payments in terms of new needed supply.

How the Proposed Demand Curve Approach Fixes These Problems

The proposal to replace the current rules with a Demand Curve approach was motivated primarily by two goals: 1) to provide protection to consumers from market power and the capacity price spikes that market power creates; and 2) to provide a stream of capacity payments to potential new generation entrants that is more stable over time and therefore more bankable than the current approach.

According to the Demand Curve proposal, the capacity payments made to generators are at a given price when capacity reserves equal the required 18 percent, at a moderately lower price when reserves are somewhat above 18 percent, and at a moderately higher price when reserves are somewhat below 18 percent. The key word in the above statement is "moderately" because, unlike the tendency of the existing approach to produce prices that either crash or skyrocket in response to changes in the demand/supply balance, the Demand Curve approach produces prices that respond much more moderately to such changes. Under the Demand Curve approach, prices rise and fall with changes in supply and demand, as all prices should; they just do so in a relatively gradual way. If enough excess supply is prevalent, the Demand Curve approach yields capacity market prices that fall all the way to zero. With the Demand Curve under consideration by the NYISO Board, this occurs when reserves reach 32 percent, which is 14 percent above the required level of 18 percent. A diagram showing the Demand Curve is attached as Figure 1.

The Demand Curve approach accomplishes the two goals that it was designed to achieve. First, it will significantly reduce the ability of generators to exercise market power to drive up capacity prices. This will significantly reduce both the financial motivation of a supplier to attempt to exercise market power as well as the actual harm borne by consumers each time market power occurs.

Second, the Demand Curve will yield capacity prices over time that avoid the extreme highs and lows that characterize the current rules; rather, capacity prices will likely be much more stable. This makes the expected multi-year stream of capacity revenues more valuable to suppliers of capital for new generation. As such, the amount of capacity that is needed to assure reliability can be obtained at a lower long-run total cost to consumers.

There are other, secondary benefits of the Demand Curve. To the extent the Demand Curve approach yields larger reserve margins in the near term, consumers will face fewer price spikes in the energy market on the system's hottest summer days. Thus, while paying more in the near term for capacity, consumers will likely pay less for energy. David Patton, the ISO's Market Advisor, has estimated that at times when the system is at its 18 percent reserve requirement, an extra 1 percent added to the reserve margin will save consumers $100 million per year in terms of reduced price spikes. Larger reserve margins also provide consumers with greater reliability.

PART III: Costs of Demand Curve

We have explained why the Demand Curve should minimize electric prices over the long term. A number of parties, including DPS Staff, have estimated the added payments that would be made to generators in 2003 and 2004 compared to what they have received in the most recent past. These estimates require assumptions as to the bidding behavior of generators both in and outside of New York State, and therefore cannot be considered definitive.

With this understanding, our estimates of increased payments to generators equate to a 1.5 percent increase in total electric bills, assuming all these costs are flowed through to ratepayers. But, many customers will not see increases due to commodity price protections that may be provided by their energy supplier.

For a customer that has no price protection, we estimate the Demand Curve could increase total electric bills by no more than three percent.

While we have used historic prices as a base to develop these impacts, a more valid comparison requires a forecast of prices if the existing methodology were allowed to continue. This is a far more difficult exercise; the existing methodology is very sensitive to the balance of supply and demand. If there are adequate supplies, we could expect prices will be unchanged, but should supplies get tight, because a plant is no longer financially viable or safety or environmental concerns require its shutdown, our analysis shows that the existing methodology is a far more expensive option than the Demand Curve. For example, the difference in payments under the existing methodology compared to those under the Demand Curve, assuming New York State is deficient, is in the order of hundreds of millions of dollars. Supplies are now tight in the New York City location, and could become tight in the upstate market if there are significant plant retirements.

We see the short-term increase in ICAP prices due to the Demand Curve as a reasonable insurance payment to avoid a much larger increase with shortage conditions under the existing approach.

PART IV: Criticisms of Opponents to the DC

- Some opponents claim that the Demand Curve is an administrative solution inconsistent with a competitive wholesale market. The Demand Curve is no more of an "administrative" solution than the current system of fixed quantity purchase requirements and penalties for shortages, which are determined by the NYISO and the New York State Reliability Council. The fact is that installed capacity provides reliability benefits to the entire system, rather than to individual customers. Therefore, it is the NYISO, not individual customers, who must determine the demand for this product. Under the current administrative system, the NYISO limits its demand to a fixed quantity, leading to excessively volatile prices. Here, the NYISO is changing specifications for reliability to a gradually sloping Demand Curve to, among other things, reflect the benefits of capacity above minimum levels.

- There has been a concern expressed that imports of capacity will not come in as a result of the Demand Curve and, hence, the New York capacity market clearing prices would be high. The FERC has worked closely with Northeast ISOs to establish regional markets for capacity and reduce barriers to trade. As a result, generation in much of the Northeast can be offered into several ISOs to get the best price. There is every reason to believe that, to the extent the Demand Curve raises capacity prices, imports will be attracted into New York's capacity market and will act to moderate the existence of a rise in prices.
- Another concern expressed is that the Demand Curve would encourage dirty, inefficient plants to remain open. The Demand Curve provides payments for installed capacity, i.e., the availability to generate, but does not require the plants to operate unless the system is in such extreme shortage that the only alternative might be shedding load. The Demand Curve

will provide equal encouragement for new, efficient plants and demand-side resources, which ultimately will permit the permanent retirement of dirty, inefficient plants when they are no longer needed for reliability.

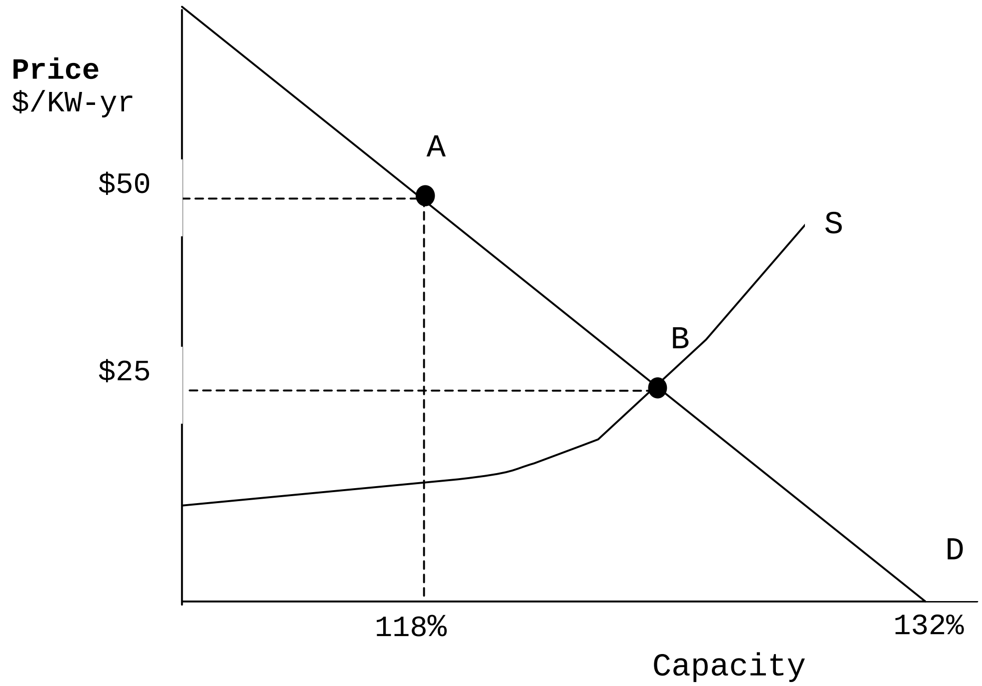
- Some suggest that if we are afraid of a shortage caused by a few plants closing, we should simply have regulated utilities engage in bilateral contracts with them, as opposed to potentially giving more money to all plants as a result of adopting the Demand Curve. However, all plants, including those that are not at risk, are providing the same service, namely, installed capacity, and in a competitive market should receive the same price for the same service. Problems accompany the reliance on a few bilateral contracts (as an alternative to the Demand Curve), because this favors a few inefficient plants over all the others, tilting the playing field. The Demand Curve provides a level playing field for all qualified suppliers, promoting the most efficient plants.
- Some argue that, if our goal is to encourage new generation, additional funding should be provided to only new entrants. Each supplier has a good story to tell. Inefficient suppliers can say they “need” the most help, because they will shut down if they do not get special bilateral contracts. New investors can say that their projects “deserve” the most help, since new plants are more efficient. Rather than trying to favor one

supplier over another, it is better to establish a level playing field that favors an efficient market outcome. That is, what will provide the lowest cost and, thus, the lowest price to customers in the long run.

- Finally, many have asked if there is a guarantee that the Demand Curve would lead to new investment in generation in the state. The Demand Curve provides market-based incentives for new investment in generation in the state. The capacity market provides a level playing field for qualified in-state generation, imports, and demand response. As load grows, the capacity market ensures that adequate resources will be added to ensure reliable operation of the electric system.

To summarize, our motivation is to ensure continued reliability of supply and fair pricing for consumers and suppliers, and we believe that the Demand Curve offers us the best chance to achieve these goals going forward. Again, thank you for the opportunity to testify before the Committee this morning. We are happy to answer questions relating to this issue.

Figure 1



APPENDIX B

Resource Demand Curve

Proposal by the New York State Public Service Commission

January 31, 2003

This document discusses the theoretical foundation of the Resource Demand Curve proposal and explains its various elements. The primary objective of this proposal is to reduce price volatility in the market for capacity resources by recognizing the value of additional capacity above minimum reserve requirements. A further objective is to reduce the vulnerability of capacity markets to the exercise of market power.

Establishing a willingness to pay (demand curve) for capacity, to be applied to all load-serving entities (LSEs) via a centralized spot auction conducted by the ITP, would accomplish these objectives. This auction would replace the NYISO's current "deficiency" auction and its related deficiency charge. The ITP would continue to allow self-supply of capacity via bilateral contracts and would continue to operate voluntary auctions within a spot market time frame to reveal spot prices.

Under this proposal, the ITP would often procure an amount of capacity above the minimum resource level. For example, if the minimum resource level is 118% of summer peak load, but suppliers offer capacity equal to 120% of summer peak load at a low enough price, then the ITP would purchase capacity equal to 120% of summer peak load and allocate this capacity to all LSEs. Thus, each LSE would be charged the market price for capacity equal to 120% of its summer peak load. This resolves the “free rider” problem, where each individual LSE currently has an incentive to purchase only the minimum capacity because the benefits of capacity levels above the minimum are largely socialized.

THEORETICAL FOUNDATION

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

Any businessperson knows well the importance of entry and how it drives the results of the market place. Ultimately, it is the cost of entrance 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 market place. If prices are high relative to the cost of new entry, then new entrants will be attracted into the market place and prices will be pulled back down. If prices are low compared to the cost of new entry, then 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 market place 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.

Why Intervene in the Electricity Market?

At the onset of electric deregulation in the United States, policymakers were concerned about whether the electric market place 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 capacity 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.[1] 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 frequency

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

because of electric shortages. Given this concern, the policy decision was made to intervene in the natural market place 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.[2] 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.

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[2] 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.

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 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.[3]

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. Based on the actual experience with this approach, discussed below, the NYPSC now recommends a switch to an alternative that works along the lines of option 2 above.

[3] This is akin to the tax deduction on home mortgages that is provided to stimulate increased homeownership.

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 Capacity Market Design

The New York Reliability Council annually determines the minimum resource levels needed to meet the standard reliability criteria of one day's (24 hours) loss of load in 10 years. The current requirement for each LSE is to procure contracts for installed capacity (ICAP) equal to 118% of its summer peak load. Deliverability of ICAP is ensured via locational requirements. Up to 2755 MW of ICAP may be procured from regions outside New York. LSEs serving load in New York City must procure ICAP equal to 80% of their in-City summer peak load from capacity in New York City. LSEs serving load on Long Island must procure ICAP equal to 93% of their Long Island summer peak load from capacity on Long Island.

The NYISO operates forward auctions for each six-month capability period (beginning May and November), and each month also operates monthly auctions for each of the remaining months of the current capability period. These auctions are voluntary and open to all parties. The NYISO accepts supply offers and demand bids (MW and price) and ranks these by price to create supply and demand curves. In each auction, the market-clearing price is paid by all chosen LSEs and to all chosen suppliers. Locational requirements can lead to clearing prices for suppliers in New York City and on Long Island above the statewide prices prevailing in the rest of the state and can lead to clearing prices for suppliers outside New York below those prices if import limits are reached.

Prior to each month, each LSE must provide contracts to the NYISO covering its ICAP requirement for the coming month. If one or more LSE's are deficient, then the NYISO will attempt to procure the deficient quantities in a centralized deficiency auction. The NYISO enters a bid for each deficient MW at a price equal to a predetermined deficiency charge and accepts supply offers from uncommitted capacity. If a sufficient amount of capacity is offered, the needed amount is bought at the deficiency auction's clearing price, and the deficient LSEs are charged that price. If the capacity offered is less than the total deficiency, then the NYISO will charge the LSEs the deficiency charge for the remaining amounts and use the funds to attempt to procure additional capacity.

Results Of Current Market Design

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 New York State does not seem excessive, it has nevertheless driven the market-clearing price down dramatically and undervalues the benefit of the additional reserve margin.

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.

OPERATION OF THE RESOURCE DEMAND CURVE

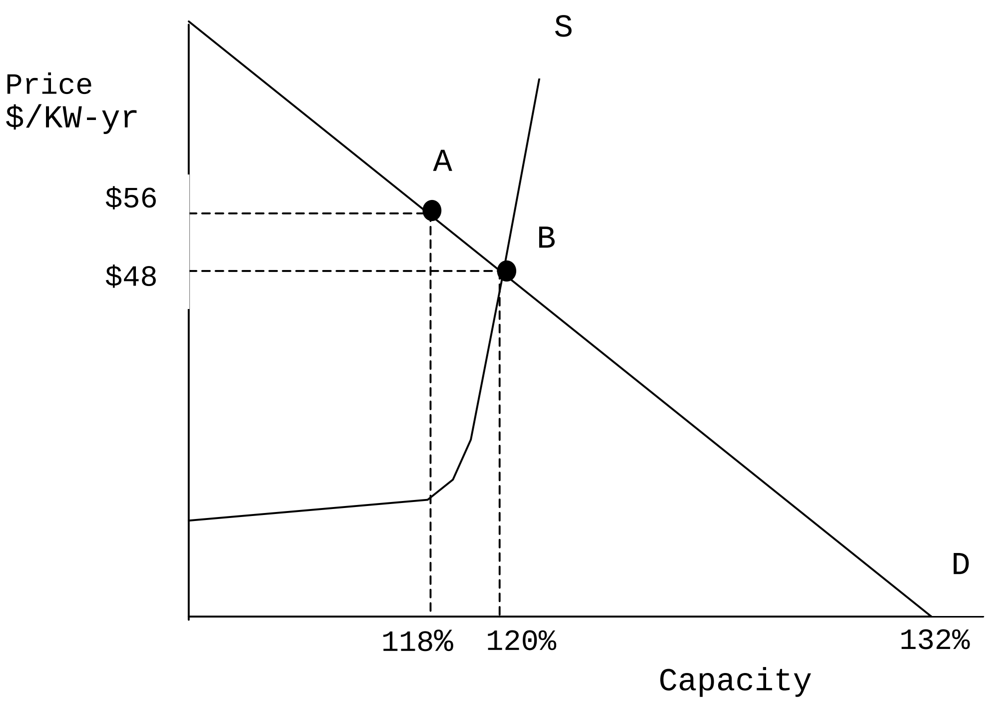
Proposed Changes

The deficiency auction would be replaced by a centralized spot auction. The buy bids that currently equal the deficiency charge would be replaced by buy bids that equal a gradually sloping Resource Demand Curve, which would be entered into the auction by the ITP. The Resource Demand Curve would be set at a level intended to encourage sufficient capacity resources to meet reliability targets. Locality requirements would continue to be recognized and may require separate, higher demand curves for New York City and Long Island. The ITP would continue its current long-term planning functions, including its annual forecast of future (20-year) load and capacity. Forecasts of impending shortages would trigger a review of the level of the demand curve. Actual resource shortages would trigger emergency measures.

Centralized Spot Auction

The ITP would operate a centralized monthly spot auction for capacity resources, replacing the current deficiency auction. In this auction, called the Demand Curve Auction, the ITP would submit demand bids for all loads in the region as a predetermined schedule of willingness to pay for capacity. By this schedule, or demand curve, the ITP would indicate a willingness to procure more than the minimum amount of capacity, but at a price that declined gradually as capacity increased. The ITP would accept offers from all qualified suppliers.[4] LSEs could self-supply by procuring supply in advance (via forward auctions or bilateral contracts) and selling into the spot auction.[5] The ITP would rank supply offers by price (from low to high) to create a supply curve. The intersection of the supply curve with the demand curve would determine the market-clearing price and quantity of capacity. All LSEs would be charged the market-clearing price for their share of the capacity. Figure 1 below depicts a demand curve auction.

Figure 1



[4] Qualified suppliers should include qualified providers of price responsive demand.

[5] This equates to the LSE selling the bilateral contract to itself; the ITP would pay the LSE the auction's clearing price for the sale, and will then charge the LSE that same clearing price for the capacity needed to satisfy the LSE's resource adequacy obligation.

The minimum reserve margin necessary to satisfy the one-day-in-ten-years criterion in New York is 18%. The annual cost of peaking capacity, less energy and ancillary services net revenues, is $56 per KW-yr. The demand curve, therefore, is established at a height such that it equals $56 per KW-yr at a capacity level of 118% of peak load (Point A). *D* is the demand curve. It is placed into the auction by the ITP. *S* is the supply curve. It represents the voluntary offers of all suppliers. The market-clearing price for capacity in this example occurs at the intersection of the demand and supply curves, at point B. The price is $48, the quantity is 120% of peak load.[6] Based on these results of the Demand Curve Auction, all LSEs are required to possess capacity rights equal to 120% of their contribution to peak load.

For example, assume an LSE has a peak load of 100 MW and contracts for 70 MW at $40 per kW-year. Suppose also that the ITP sets the Resource Demand Curve to $56 per kW-year at a quantity equal to 118% of peak load, gradually declining to $52 at 119%, $48 at 120%, etc. In the spot auction, the LSE would offer its 70 MW contract towards its resource requirement. The ITP would add this to all other resource (supply) offers to come up with a supply curve and compare this to its Resource Demand Curve. Suppose the spot auction clears (i.e., supply and demand curves cross) at a price of $48 per kW-year and quantity of 120% of peak load. The LSE is allocated a resource requirement of 120 MW and is charged

[6] The numbers used are illustrative.

for an additional 50 MW (120 MW minus 70MW) at the spot price of $48 per kW-year.

For another example, assume the LSE had contracted for 122 MW at $40 per kW-year. In that case, it would have been credited with a net sale of 2 MW in the spot auction, at the spot price of $48 per kW-year. The LSE would still own 122 MW under its long-term contract; it simply would have been compensated at the market price for providing an extra 2 MW of resources.

Setting the Resource Demand Curve

The Resource Demand Curve would be set high enough to ensure that reasonable amounts of capacity resources are supplied in the long run. In the vicinity of the minimum resource levels, the demand curve should reflect the long-run cost of capacity. An estimate of the cost of capacity is provided by the annual cost of a new combustion turbine, offset by net revenues from energy and ancillary services.[7]

Based on a preliminary analysis of the cost of new gas-fired combustion turbines in the Northeast (including a conservative, i.e., understated, estimate of net revenues from energy and ancillary services), the NYPSC estimated an annual cost of $64 per kW-year (for a generic upstate New York location). This would establish the level of the Resource Demand Curve at the NYISO's minimum resource level of 118% of summer peak load. The NYPSC has

[7] Other resources, including demand-side resources and older, inefficient generation, may be able to provide capacity at lower cost.

proposed that the Resource Demand Curve decrease at a uniform rate (straight line) to $0 at 132% of summer peak load. The gradual slope is intended to provide reasonable price stability and avoid market power problems associated with much steeper curves (the amount that price will rise in response to the withholding of supply depends on the steepness of the demand curve).

The locational requirements for New York City and Long Island would also be replaced by locational Resource Demand Curves, indicating a willingness to procure more than the minimum requirement from resources in each constrained location. For these localities, the cost of capacity may be higher; if so, the locational Resource Demand Curves would be set higher. For example, the NYISO currently requires LSEs serving Long Island load to procure resources equal to at least 93% of summer peak load from Long Island resources. The Long Island Power Authority has suggested replacing this with a separate Resource Demand Curve for Long Island, starting at a price higher than that for upstate for capacity at 93% of peak load and declining uniformly (in a straight line) to $0 at 110% of peak load.

Offsets For Net Revenues From
Energy and Ancillary Services Markets

In considering the demand curve approach it is important to acknowledge the crucial difference between it and the existing ICAP rules. The existing approach involves setting a quantity target, 118% for the statewide market, requiring all LSEs to acquire sufficient capacity to meet the requirement and enforcing it with a deficiency charge. The precision with which the deficiency charge is quantified is not terribly important. It simply serves as a deterrent to LSEs that might otherwise fail to be diligent about meeting the requirement.

In contrast, the demand curve approach requires a much more carefully estimated set of values because it involves setting a series of prices that the system will pay for specific amounts of capacity, and then letting the market reveal the quantity of capacity that is willing to commit to the system at each price. Accordingly, a demand curve that is too high will directly cause the system to pay too high a price for capacity. The opposite occurs for a demand curve that is set too low.

The demand curve approach is, to a large extent, self-adjusting since a price that is too high and elicits too much quantity of capacity will cause the price to come down as the additional quantity drives one further out and down the curve to a price that is lower than it would have been for a lower quantity. Nevertheless, unlike the existing ICAP approach, under a demand curve approach, the numbers one uses to establish the demand curve directly impact the price that is paid.

There are two key steps in developing an estimate of the price, per KW-yr, that a new generation entrant would need in the capacity market for entry to be economic. First, one must estimate the annual carrying costs of a new gas-fired combustion turbine. Second, one must estimate the expected net revenues that a new combustion turbine would earn, per year, by selling into the energy and ancillary services markets. The extent to which the net revenues from the energy and ancillary services markets fail to cover the combustion turbine's annual carrying costs becomes the basis for determining the capacity revenues that the new generator needs to receive. In other words, the price needed in the capacity market is a combustion turbine's annual carrying cost, offset by its expected net revenues from the energy and ancillary services markets.

In practical, numerical terms, it is very important to account for the energy and ancillary services markets' offsets in estimating the annual cost of new entry. Failure to account for the energy and ancillary services markets' net revenues can result in a severe overpayment to generators because the curve would be set too high.

The offsets for energy and ancillary services net revenues should be estimated based on the assumption that the electric system is exactly at its minimum required reserve margin (in New York, 18%). This estimate is frozen for purposes of setting the height of the demand curve, i.e., the estimate of the offsets does not grow or fall as a function of the actual level of reserves. If this is done, then, at a 18% reserve margin, the expected net revenues received by a combustion turbine, which equals the sum of the capacity market revenues (using the Resource Demand Curve), the energy market net revenues, and the ancillary services market net revenues, will equal a combustion turbine’s estimated annual carrying charges. For reserve levels substantially in excess of the minimum required level, the above revenue streams will sum to an amount that signals potential combustion turbine entrants to stay out, at least for a while, as they are not yet needed.

Conservative Estimates Can Be
Used To Assure Resource Adequacy

The annual cost of new entry, net of the energy and ancillary service offsets, provides a reasonable value upon which to base the Resource Demand Curve. It sets the price point on the Resource Demand Curve at which it crosses the minimum required reserve level (118% in New York). Of course, it is prudent, from a resource adequacy standpoint, to err somewhat on the side of an overestimate of the capacity payment needed to ensure that entry of new generation becomes economic as the system’s reserve margin drops down toward its minimum required level. This can be accomplished be building a slight cushion, such as a 10% adder, into the estimate of the cost of new entry. A slight overstatement causes little harm since, if new entry truly is less costly than the estimate, additional new entry will add to the system’s reserve margin and move down the demand curve to the point at which the demand curve’s price equals the cost of new entry. This is the self-correcting aspect of the downward sloping demand curve. The added cost to society is simply the capacity cost of a slightly larger reserve margin (a few percent), which is largely offset by the benefits of a larger reserve margin.

The economics of new entry, given the Resource Demand Curve, is worth describing briefly. Consider a situation in which load growth was occurring in the absence of new generation entry. As load growth occurs, the capacity reserve margin steadily shrinks. As the reserve margin shrinks, the expected profitability of a potential new entrant grows in two ways. First, revenue from the capacity market grows as the shrinking reserve margin causes a movement up the demand curve to a steadily higher capacity market price. Second, net revenue from the energy and ancillary service markets grows as increased tightness of these markets causes their prices to rise.[8]

As one approaches the minimum reserve level, the growth in energy market revenues becomes pronounced and, when combined with the capacity market's revenues, yields an environment in which new entry becomes profitable. One can think of the growth in energy market revenues as the key driver of entry, with the Resource Demand Curve supplementing it as it also produces ever growing capacity revenues in response to a lessening of capacity reserves.

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[8] As noted in the previous section, the energy and ancillary services markets' offsets used in establishing the Resource Demand Curve are based on an assumed level of reserves that equals the minimum reserve margin. As such, as the actual system gets tighter, the actual energy and ancillary service markets' revenues ramp up, but the offsets assumed for purposes of setting the height of the demand curve stays fixed.

Response to Capacity Deficiencies

The NYISO currently forecasts load growth and capacity additions to provide an early warning of impending shortages. Under the Resource Demand Curve proposal, tight supply conditions would automatically increase capacity prices, encouraging additional supply. In addition, the ITP could respond to persistent tight conditions by increasing the level of the Resource Demand Curve, to provide a greater cushion and avoid actual deficiencies.

In the event of an unanticipated actual deficiency, the ITP would be permitted to take emergency measures to ensure reliability. The ITP could purchase capacity or take other measures, tailored to the specific nature of the shortage (e.g., whether it was due to a few months' delay in new generation or a long-term inadequacy). The costs of these emergency measures would be charged to the appropriate LSEs, but would not set market-clearing prices. The ITP could also review the level of the Resource Demand Curve to determine if it should be increased prior to the next capability period.

An Example of Volatility Reduction

A simple numerical example can be used to demonstrate the volatility reducing properties of the Resource Demand Curve. Through this example, the spot capacity prices produced by the Resource Demand Curve are compared to the spot capacity prices produced by the current NYISO deficiency charge approach over a hypothesized 15-year period.

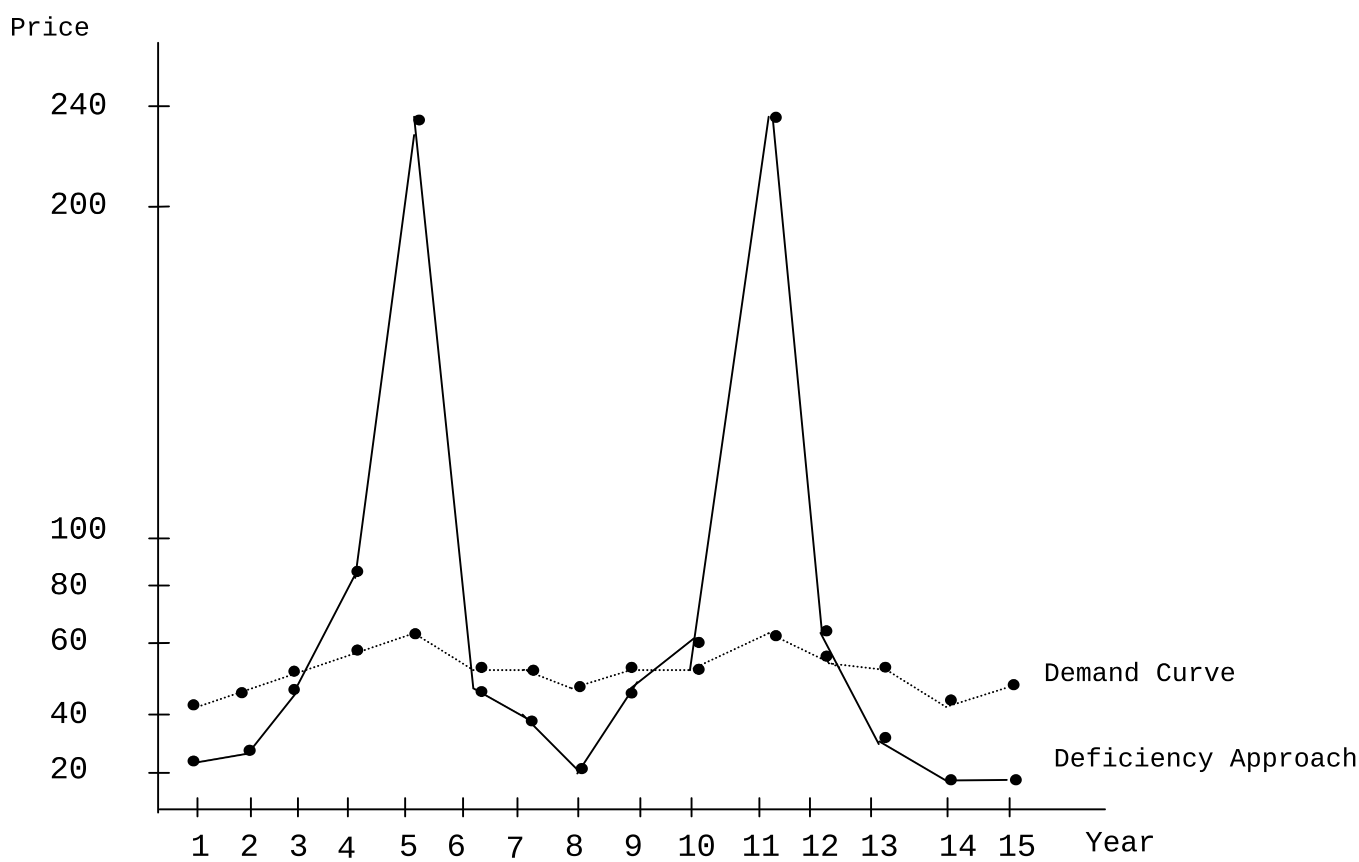
Consider a 15-year period in which there are years with large surpluses, years with modest surpluses, and years with deficiencies. The deficiency charge approach will yield extremely high capacity prices, equal to the deficiency charge, during years in which the system is deficient, extremely low prices when the system is safely in surplus, and intermediate prices for years of small surpluses. The Resource Demand Curve approach will yield prices that track the gradual slope of the demand curve; they will be higher in years of tight capacity and lower in years of surplus, but will not vary dramatically from one period to another.

Table 1 and Figure 2 compare the pattern of yearly capacity prices that would arise from the two approaches over a hypothesized 15-year period. One can see the extreme volatility of the deficiency approach, which depends heavily on an occasional extreme price spike in the capacity market to generate substantial funds. In contrast, the Resource Demand Curve approach is much less volatile and yields a more dependable capacity market revenue stream to potential new generation entrants.

Table 1

Year	Reserve Margin	Deficiency Approach's Capacity Price	Resource Demand Curve's Capacity Price
1	23%	$12	$36
2	22%	$13	$40
3	20%	$40	$48
4	18%	$80	$56
5	17%	$240	$60
6	20%	$40	$48
7	21%	$24	$44
8	22%	$13	$40
9	20%	$40	$48
10	19%	$60	$52
11	17%	$240	$60
12	19%	$60	$52
13	21%	$24	$44
14	23%	$12	$36
15	22%	$13	$40

Capacity Price Volatility: Deficiency Approach vs. Demand Curve



Example Of Market Power Mitigation
Benefit Of Resource Demand Curve

One of the concerns that has been continually raised about the current deficiency charge approach for capacity requirements is its vulnerability to the exercise of market power. With a deficiency charge that equals a multiple of the estimated annual carrying charges of a combustion turbine (three times for the NYISO), the financial benefits to a generation owner during times of deficiency are so huge that a large supplier may be tempted to artificially induce a deficiency by withholding capacity from the market.

For example, assume a situation in which the system is within 500 MWs of being deficient and capacity prices are clearing at $60 per kw-yr. A 2000 MW supplier can act competitively, i.e., as a price taker, and sell all 2000 MW at $60. Alternatively, it could withhold 1000 MW, half its capacity, and drive the price to a $240 per KW-yr deficiency charge. Such an act is profitable since the supplier sells only half as much, but at quadruple the price. This problem is caused by the sudden jump in prices inherent in the existing deficiency charge approach.

In contrast, the Resource Demand Curve, because it uses a gradually sloped demand curve, yields only modest price increases for an act of withholding. If supply is withheld, the market-clearing price moves up and to the left along the Resource Demand Curve, raising the price, but not in any dramatic way.

For example, consider the same 2000 MW supplier, under a Resource Demand Curve regime, facing a competitive price of $40 per kw-yr. If it withheld 1000 MW, which for New York State as a whole represents about a 3% reduction in reserves, the price would rise along the demand curve to $52. Since the supplier's quantity sold drops by half, the price would have to more than double for the withholding strategy to be profitable, yet the price falls well short of doubling. The withholding strategy, therefore, is not profitable.[9]

Table 2, below, shows the results of the same withholding strategy at different prices in the market, under the Resource Demand Curve approach.

[9] The example assumes that no costs are shed by withholding from the capacity market.

Profitability of Withholding in Capacity Market Resource Demand Curve Approach Table

Starting Price $per kw-yr	Revenue At 2000 MW Sold	Price If 1000 MW Is Withheld	Revenue at 1000 MW Sold	Revenue Gain From Withholding
52	$104 mill.	64	$64 mill.	$40 mill.
44	$ 88 mill.	56	$56 mill.	$32 mill.
36	$ 72 mill.	48	$48 mill.	$24 mill.
28	$ 56 mill.	40	$40 mill.	$16 mill.
20	$ 40 mill.	32	$32 mill.	$ 8 mill.
12	$ 24 mill.	24	$24 mill.	0
4	$ 8 mill.	16	$16 mill.	$ 8 mill.

A look at Table 2 reveals that withholding is unprofitable for a 2000 MW supplier at all market prices other than the very lowest price ranges. These low price ranges will occur only at time of large surpluses. For more normal years, the market will clear at more normal prices, and will be relatively free of market power concerns.