Capacity for the Future:

Kinky Curves and Other Reliability Options

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Foreword

This paper is an effort by Synapse Energy Economics to provide an informative and useful document to several clients and a larger audience of regional stakeholders in the NY ISO, ISO-NE, and PJM control areas. Discussions about resource adequacy and the appropriate mechanisms that might achieve resource adequacy at a reasonable cost have engaged the Northeast ISOs, their stakeholders, and their regional and Federal regulators for the last several years.

Over that time, Synapse has worked with the Connecticut Office of Consumer Counsel, the Maine Office of the Public Advocate, the Massachusetts Attorney General, the Maryland Office of People's Counsel, the New Hampshire Office of Consumer Advocate, the Pennsylvania Office of Consumer Advocate, and the Rhode Island Attorney General to better understand the specific ISO proposals for resource adequacy and alternative approaches. This paper represents much of what we have learned during that time.

The views expressed in this paper are Synapse's. They do not necessarily reflect the views of any of our clients or entities that we have worked with over the last several years and, in particular, they do not necessarily represent the views of any of the state agencies mentioned above. This paper is a starting point for a comprehensive understanding and discussion of resource adequacy options. Synapse looks forward to engaging in further discussions with stakeholders and other interested parties in the coming months.

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A. Introduction and Summary

Objective of this Report

This report reviews numerous mechanisms that are designed to ensure resource adequacy for regions that have adopted ISO[1] administered competitive wholesale energy markets. These mechanisms include proposals for "demand curves"[2] as well as alternative mechanisms. We are particularly focused on the demand curve mechanisms given the Federal Energy Regulatory Commission's (FERC's) apparent endorsement of these mechanisms without an evidentiary proceeding to establish that the costs imposed by demand curves meet the "just and reasonable" standard of the Federal Power Act.[3] Our review of the demand curve approach has identified serious concerns regarding demand curves. These include analyses that show that demand curves are likely to dramatically and unnecessarily increase electricity costs, provide windfall profits to many existing generators, not provide sufficient revenues for new entrants, and not ensure reliability. In addition, demand curves will require frequent, contentious, administrative decisions regarding the numerous pre-determined price points on the demand curve. As many have noted, the ISO proposed demand curves are not market-based mechanisms.[4]

We also review alternative mechanisms that may provide greater assurances of reliability at substantially less cost. While these mechanisms, like demand curves, require administrative determinations, they may offer greater assurances of revenue streams to resource providers in ways that will both encourage new entrants and properly compensate existing resources. The fact that these alternative mechanisms are not "pure market mechanisms" should not disqualify then from consideration as alternatives to demand curves, since important decisions involving electric system reliability and billions of consumer dollars should be based on solid analysis and good judgment rather than ideology (and, of course, demand curves are not pure market mechanisms, either).

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[1] ISO stands for Independent System Operator. For the purposes of this report, we do not distinguish between ISOs and Regional Transmission Organizations (RTOs). PJM is an ISO and a FERC-approved RTO; ISO-NE is a FERC-approved RTO but not yet operational as an RTO; NY ISO has not been approved as an RTO. Whether they are ISOs or RTOs, all three entities perform similar functions within their regions in regard to reliability and market design and implementation.

[2] The phrase "demand curve" has been used to describe the administratively determined price curves (actually straight lines) for setting payments to resource providers for the installed capacity value of their resources. These mechanisms are not demand curves in the normal economic sense of that term.

[3] FERC approved the NY ISO demand curve mechanism as a "settlement package" proposal sponsored by the NY Public Service Commission, NY ISO, and a majority of NY ISO stakeholders in Docket No. ER03-647-000, Order of May 20, 2003. FERC has approved the ISO-NE demand curve approach as part of a compliance filing in a proceeding on reliability must run compensation issues in Docket No. ER03-563-000, et sequel. The compliance filing of March 1, 2004, by ISO-NE was not supported by the ISO-NE stakeholder body (New England Power Pool, or NEPOOL) or the regional regulatory association (New England Conference of Public Utilities Commissioners, or NECPUC) and the specific parameters of the demand curve are the subject of a FERC litigation process.

[4] This paper does not examine the issue of whether FERC has jurisdiction to approve capacity purchase mechanisms that set capacity quantities; some have argued that this issue is reserved to state regulatory agencies.

The objective of this report is to identify the numerous and substantial problems with FERC's premature endorsement of demand curve mechanisms, outline some alternative mechanisms, and encourage further discussion among regional stakeholder groups. The goal of the stakeholder discussions is to develop resource adequacy mechanisms in the Northeast (and elsewhere) that are effective and achieve an appropriate balance between the revenues provided to resource providers to ensure reliability and the costs that are assessed to consumers for that reliability.

Background

Currently, there is a surplus of available electric generating supply throughout the Northeast. However, this surplus is not expected to last. By 2009, there may be localized shortages of electric capacity in certain regions due to current load growth and planned generation retirements that will require additions of new resources.[5] Having enough installed resource capacity available to customers is a key factor in serving electricity customers reliably. Yet, figuring out how much capacity will be needed in the future and getting it online and ready for use is extremely challenging and complex. The process involves a great deal of planning, bidding among resource providers, financing, coordinating across States and across regions, policy decisions, market rules, and more.

The question that this paper explores is how best to provide for adequate quantities of resources in a deregulated marketplace. On the one hand is the need for enough capacity to avoid brownouts and blackouts. On the other hand, having capacity available is far from cost free. We should attempt to strike a balance in which capacity is added to the bulk power system in amounts that provide acceptable levels of reliability at reasonable cost.

Historically, under cost-based regulation, integrated utilities had the responsibility for providing adequate energy and capacity. For such efforts, the utilities were paid their costs along with a regulated rate of return on investments. Such a system had an inherent tendency towards excessive capital investment because utilities generally expected to pass their costs on to their customers. To some extent this system can be blamed for the excess capacity and cost overruns of nuclear generation resources and the associated rate shocks of the 1970s and 80s.

Thus, being dissatisfied with cost-based regulation, a number of states moved to deregulate the electric sector with the expectation of greater overall efficiency and lower customer costs. This has been an on-going process since the late 1990's. During this period, a number of specific approaches to ensure an adequate capacity supply have been tried and subsequently modified. Central to this deregulation process are Independent System Operators (ISOs,) who manage the system operation and mediate between suppliers and customers via a number of market structures. Some of the electricity "products" and their related markets include: energy (both day-ahead and real-time), reserves (spinning and quick start), regulation, transmission, and capacity. In addition, some of these markets are further segmented on a locational basis.

It is important to keep in mind that the combination of the above mentioned markets delivers adequate revenues to keep most generation facilities operational. In fact, it is only some

[5] New England currently has some load pockets that have capacity deficiencies that require the operation of "out-of-merit" generation. *See*, RTEP04, November 2004. PJM anticipates a similar situation starting in 2007. *See*, PJM RAM Stakeholder Working Group, Presentation 3, December 9, 2004. Neither region anticipates "insufficient" generation before 2009.

marginal resources that need additional financial incentives. Those resources fall into two categories (1) high cost resources critical for grid stability in some load pockets and (2) new resources as needed to maintain adequate reserve margins. The basic question then is how to provide adequate financial incentives for specific resources without incurring unnecessary payments (and customer costs) for the other resources that do not need financial assistance to remain operational.

Northeast ISO Demand Curve Proposals

To address the perceived flaws with existing capacity pricing structures, the Northeast ISOs have been looking to adopt a more continuous demand curve approach. This approach is intended to (1) reduce the severity of the price fluctuations, (2) provide payments for existing capacity, and (3) provide a price signal for new capacity where and when needed. The basic structure of a demand curve is a downward sloping line that decreases the per unit (megawatt) payments as the quantity of resources being purchased increases (see Section B).

Nearly all demand curve approaches are, over the long-term, designed to produce capacity payments for all resources (existing and new) that are equivalent to the cost of new resource entry. Unfortunately the cost payments to the existing resources will be substantial and mostly unnecessary, because they have already recovered most of the costs associated with their capacity. Providing additional payment, under most circumstances, would fail to meet the standard of “just and reasonable” costs under the Federal Power Act. In other words, providing new entry payments to existing resources results in a windfall for those resources, as they do not “need” this money to operate – the plants are already built and operating in the marketplace.

To illustrate the magnitude of this issue we can look at the actual capacity costs versus what would be paid in a single-price market based on the marginal cost. The graph below is for PJM for the 2008/2009 capacity market year[6].

[6] PJM RAM Stakeholder Working Group, Presentation 3, November 9, 2004.

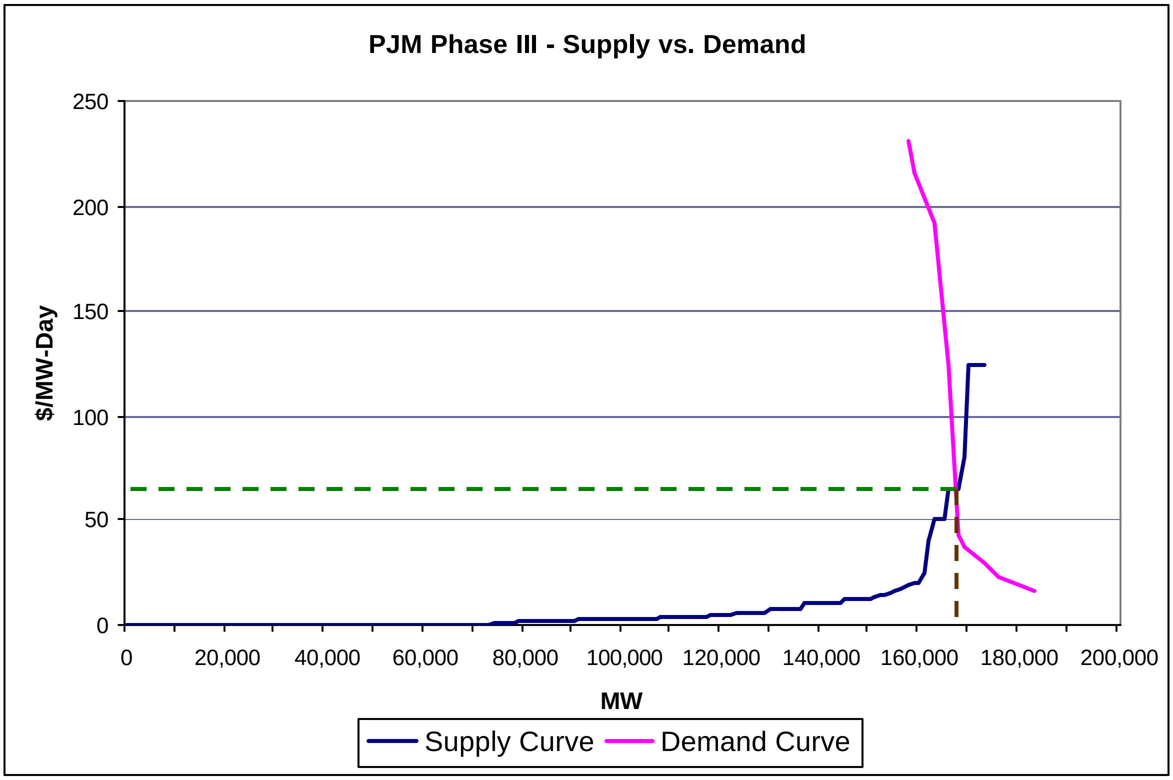

Figure 1. PJM Capacity Supply and Demand for Phase III – 2008/2009

The Supply Curve is the rising blue line that represents the payments that various resources need to stay in operation. The downward intersecting magenta line represents the proposed PJM Demand Curve whose horizontal location depends on the targeted capacity level. The dashed lines delineate areas representing comparative costs.

Assuming a capacity level indicated by the intersection of the supply and demand curves (~168,000 MW), the marginal capacity price would be about 65 $/MW-day. The actual payments necessary for those resources (indicated by the triangular area under the supply curve up to the vertical dashed line) would be approximately $950,000 per day or $350 million per year. But if all capacity (new and existing) were paid the marginal price (indicated by the rectangular area within the dashed lines), the payments would be $11,000,000 per day and the annual costs about $4,000 million[7]. This is an 11-fold increase. Furthermore at the anticipated market equilibrium price of 125 $/MW-day based on the entry cost for new capacity, those impacts would be doubled. This is the basic conundrum of single price capacity markets based on the cost of the most expensive marginal resource.

To further understand the magnitude of the cost impacts of demand curve approaches, consider the same PJM supply curve over time. The graph below looks at three points in time: today, the 2008 power year, and a future time when demand reaches the target price for new entry.

[7] The basic calculation for this is: 65 $/MW-day x 168,000 MW = 10,920,000 $/day. 10,920,000 $/day x 365 days/year = 3,986 Million$/year. If the marginal cost increases to 125 $/MW-day, the total impact is 7,665 Million$/year.

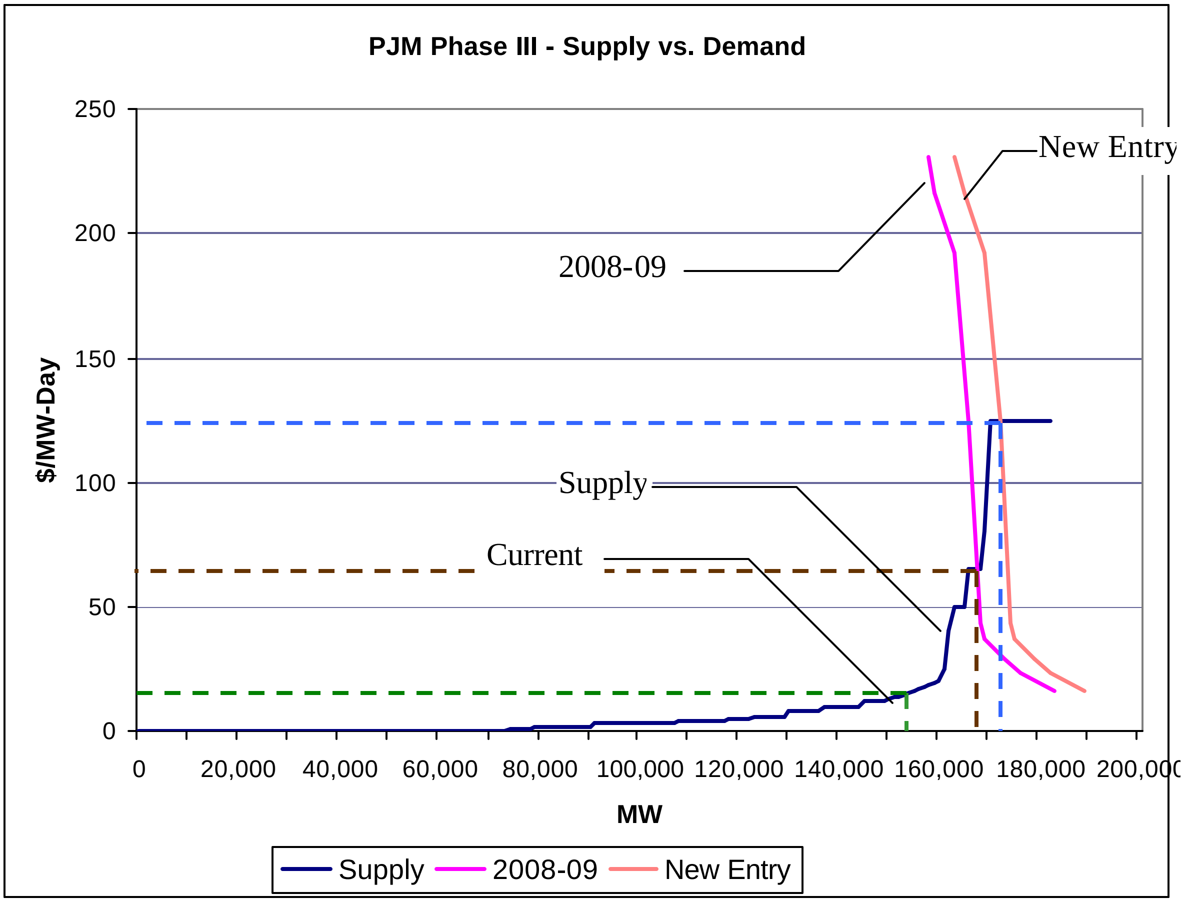

Figure 2. PJM Capacity Supply and Demand for Phase III – 2008/2009 plus new entry

The roughly triangular areas under the blue supply curve at the three demand intersection points produce the supply curve costs. The rectangles shown by the dotted lines at the three demand intersection points produce the demand curve costs. The table below shows the comparative cost impacts of the supply curve and demand curve for the three levels of demand. As part of the specific discussion of PJM's demand curve approach in the next section of this paper, we provide a more detailed explanation of this graph.

Table 1. Summary of Variable Demand for the PJM Supply Curve

Period	Current	2008-09	Cost of New Entry	Unit
Price of Capacity	$15	$65	$125	$/MW-day
Supply Curve Cost	$247	$355	$521	Million$/Year
Single Market Price Demand Curve Cost	$843	$3,986	$7,848	Million$/Year
Demand Cost/ Supply Cost Ratio	3.4	11.2	15.1	

Resource providers may be correct that payments equal to the area of the small triangles may undermine long term financial viability by not providing any contributions to imbedded capital costs. However, payments equal to the area of the large rectangles will overpay resource owners by providing proxy peaker capacity revenues to all resources, regardless of their costs. Some intermediate approach between the supply curve cost and single market pricing might produce a more appropriate result for both resource providers and consumers.

Alternative Mechanisms Are Available

Aside from the demand curve approach, there are several alternative methods for procuring capacity resources. Some may significantly reduce the cost impacts to consumers. These approaches include various ways to differentiate between capacity resources (new versus old, segmented auctions, pay as bid, etc.); the use of central purchase options (traditional RFPs or special auctions); or explicit transition mechanisms. These alternatives can help achieve longer-term, stable prices and reduce market power concerns.

As with the demand curve options, they combine administrative and market mechanisms to ensure reliability. One attractive option is the "Reliability Option" proposed in the New England LICAP litigation. This alternative combines several market based features with an auction that provides a three-year purchase commitment for new resources. Unfortunately, however, the Reliability Option and other alternatives have been procedurally excluded from that process.[8]

In later sections of this paper, we consider these alternatives and provide a comparison between some of these alternatives and the ISO demand curve approaches based on certain key criteria.

General Findings

Our review of the ISO demand curve proposals and alternative mechanisms produced the following findings:[9]

- ISO demand curves provide existing resource providers with windfall profits; amounts could be on the order of $7 billion per year in PJM and close to $2 billion per year in New England;
- ISO demand curves may not provide new entrants with a sufficiently stable stream of likely revenues to allow them to obtain the long-term financing necessary to build new resources;
- ISO demand curves may not provide an incentive to eliminate local constraints because in certain cases they increase total costs to all consumers when constraints are removed;
- ISO demand curves and the alternative mechanisms all use administrative determinations to set prices; none of the proposals is entirely a market mechanism;

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[8] *See*, ER03-563-30, Pechman testimony at 79-129, November 4, 2004. Pursuant to FERC's Order on Rehearing and Clarification, ER03-563-38, November 8, 2004, alternative proposals to ISO-NE's locational ICAP proposal are outside the scope of the proceeding.

[9] These findings are discussed at greater length in Section E.

- An acceptable mechanism must demonstrate that it can provide an adequate quantity of resources to maintain reliability at a reasonable price;
- The ISO demand curve proposals are each so different that there will be seams issues between regions;
- The ISO demand curves will require constant updating of assumptions through contentious proceedings; the alternative approaches may require different assumptions but they may be no less contentious;
- Market power concerns about existing resources, particularly in load pockets, are not eliminated with the adoption of ISO demand curve approaches and ISO demand curves encourage existing resources to prevent new entry; and
- An "integrated resource approach" may have some usefulness in creating an appropriate mechanism, as do some of the "forward market" concepts being considered in electricity and other commodity markets.

We conclude that the selection of a mechanism for ensuring resource adequacy is a policy issue that requires a balancing of market options (competitive bids, auctions, etc.) with administrative parameters (bid caps, quantities, etc.) to achieve appropriately priced reliability. The Federal Energy Regulatory Commission (FERC) appears to have prematurely accepted a single mechanism, demand curves, without fully understanding the significant cost implications or effectiveness of such a choice. We recommend that an open dialogue among a broad group of regional stakeholders consider ISO demand curves and alternative approaches and that ISOs, due to their primary focus on reliability and indifference to market outcomes, not be the sole developers of a long-term resource adequacy mechanism.

In the remaining sections of this paper we examine in detail the ISO demand curve proposals and identify some alternative demand curves (Section B); outline several alternatives to the ISO demand curves (Section C); compare the ISO demand curves to a few of the alternatives (Section D); and then present our overall findings and conclusions (Section E). The Appendices at the end of the report look at several issues in greater detail.

B. Demand Curves

NY, PJM, and New England ISO/RTO entities each have ongoing efforts to develop effective and efficient programs for ensuring electric generating resources in their respective regions. Although all three organizations incorporate a "demand curve" mechanism in their current proposals, each proposal uses the demand curve in a different manner and constructs its demand curve based on different assumptions. This section describes the basic components of demand curves, the three ISO's demand curves, and some of the alternative demand curves proposed by stakeholders.

Demand Curve Components

One way to try to ensure that enough capacity is available is to send market signals to owners of generating facilities with regard to the market price for capacity. In other words, as long as generators fully understand how much their capacity will be worth in the electricity marketplace, they can profitably plan, build, and operate generating facilities. Alternatively, they can choose to shut down or sell facilities that are no longer in need. For their electric capacity market signals, each of the ISOs studied herein has chosen to utilize a demand curve approach. Below we describe the essential attributes of proposed ISO demand curves by looking at the ISO-NE demand curve filed in the FERC LICAP proceeding.[10]

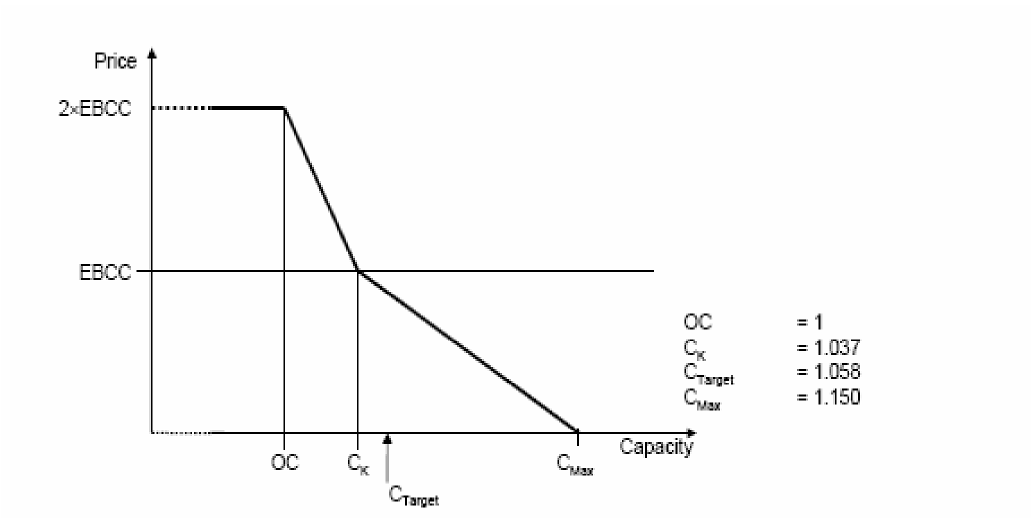

Figure 3. Components of ISO-NE Demand Curve

Just like any other economic demand curve, the capacity demand curves show quantity on the x-axis and price on the y-axis. In our specific context, the x-axis is further defined as the % of installed capacity available to the marketplace. The downward slope of the curve indicates that market prices are higher when less installed capacity is available to the marketplace. As this capacity is filled, less money is paid to generating facility owners to keep this capacity available to the marketplace.

The important elements of a demand curve include the following: the price for new entry (EBCC), the minimum resources needed for reliable operation (OC or IRM), the target quantity of capacity resources desired (Ctarget), the maximum quantity of capacity resources that will receive compensation (C max), and the quantity of capacity resources that are paid the maximum, capped price (Cmin). Each of these points is discussed in greater detail below based on the above sample curve.

(a) Setting the Estimated Benchmark Capacity Cost (EBCC)

In order to encourage the entry of new resources, a price is established that is supposed to reflect the annual levelized cost of new entry. This value has been defined as the estimated cost of a combustion turbine (CT) or proxy peaker unit. This may be the most straightforward element, although it is remains a contested issue. Each of the Northeast ISOs

[10] Docket ER03-563-30, Stoft testimony at 16, August 31, 2004.

has calculated different values for a new proxy peaker unit despite the use of an identical generic unit.[11] While there are undoubtedly some variations in regional construction costs, the large variance between the three ISO estimates suggests that further comparative analysis is warranted. The different results are driven primarily by different estimates of labor costs involved in peaker construction. There is also a small variance in the financial assumption category. While the price estimate of a proxy peaker will have a direct impact on the structure of the demand curve and the prices it produces, for the purposes of this paper we take the proxy peaker price as a given assumption and focus on the other aspects of the demand curve.

(b) Setting the capacity goal (Ctarget)

The capacity goal is the long term average amount of resources that a region wants to procure. It is the intersection of points on the y and x axes that represent the proxy peaker price (EBCC) and the capacity (quantity) goal. Traditionally, this capacity goal has been the quantity of capacity that will meet the "one day in ten years" loss of load event probability standard.[12] It can also be stated as OC (Objective Capability), IRM (Installed Reserve Margin), or Peak Load Plus Reserves. New York adopted a 1.0 standard; New England has proposed a 1.054 standard[13]; and PJM is currently using a 1.0 target. 1.0 is the quantity of capacity that is equal to the one day in ten years standard. 1.04 is a quantity of capacity four percent above the one day in ten years standard. The capacity goal value is a critical component of the demand curve and has significant cost/revenue impacts.

(c) Setting the cap (Cmin)

The cap is a value that provides some protection against market power and market failure. Market power is the ability to raise prices above competitive levels, so the cap provides some protection against the exercise of market power by setting an upper limit on prices. Market failure is the inability of prices to obtain sufficient resources to meet reliability needs, so the cap provides additional compensation above EBCC to encourage sufficient quantities of resources to be available. ISO-NE chose a value of two times EBCC, because it seemed high enough to strongly encourage market entry under conditions of capacity scarcity. Others have suggested that values of 1.2 or 1.5 times EBCC provide a sufficiently strong investment signal.[14] As the specific ISO and other graphs below demonstrate, the cap value has a significant impact on potential total costs.

(d) Setting the zero point (Cmax)

The "zero point" is the point on the x-axis where the value of capacity is zero. Up to that point, there is presumed to be a value to additional capacity. One interesting way to

[11] See Appendix A for a chart that compares the three ISO estimates of proxy peaker costs.

[12] The "one day in ten years" standard is set by the Northeast Power Coordinating Council (NPCC), a regional entity that establishes reliability standards. The NPCC standard applies to both NY ISO and ISO-NE; PJM also must meet a one day in ten years LOLE set by its regional reliability entity MAAC.

[13] As discussed later, ISO-NE intends to achieve an average capacity level of 1.054 (the New England historical average for the last 21 years) by setting the average purchased capacity level at 1.037.

[14] *See*, ER03-563-030, Pechman testimony at 53, 66, and Daly testimony at 37-38, November 4, 2004.

understand the “zero point” is to look at it as a proxy for the loss of load expectation (LOLE) probability standard. At 1.0, the LOLE probability is one day in ten years. At 1.05, the LOLE is about one day in 50 years. At 1.065, the LOLE is about one day in 100 years; at 1.10, the LOLE is close to one day in 300 years. At 1.15, the LOLE is one day in 1250 years.[15]

(e) Adding kinks (Ck)

Kinks can be added to achieve additional policy goals. ISO-NE adds a kink at the capacity goal point (1.038) so that the demand curve slope provides a steeper incentive to the left of the point (when the region is below the capacity goal) than when it is to the right (capacity in excess of the goal). ISO advocates for the kink for two reasons: first, it provides an extra incentive for new entrants when system resources are low, and second, it will achieve an average system resource level equal to the 21 year historical value of 1.054.[16] Kinks are additional administrative adjustments to the price points on the demand curve that act to encourage specific quantities of resources.

ISO Capacity Proposals

1. NY ISO

New York was the first ISO control area to propose a “demand curve” approach to replace the traditional capacity deficiency penalty mechanism. The NY ISO sponsored a year-long stakeholder process to review a demand curve proposal initially advanced by the New York Public Service Commission (NYPSC). The key dates in the development, filing, and implementation of the New York demand curve approach are as follows.

- In May 2002 the NYPSC introduced its demand curve proposal and the NY ISO sponsored eighteen stakeholder meetings to discuss, refine, and modify the initial proposal.
- In March 2003, the NY ISO filed its demand curve proposal with the FERC to replace the existing installed capacity market (which consisted of a resource purchase requirement of 118 percent of the annual peak load estimate and a deficiency assessment of three times the cost of a new peaking unit for any load serving entity that failed to acquire its required capacity).
- In May 2003, FERC approved the NY ISO demand curve proposal with conditions that the NY ISO provide annual reports on the performance of the demand curve and any withholding behavior that occurs.

[15] These specific values refer to the New England control area and are taken from testimony in the LICAP litigation. *See*, ER03-563-030, Daly testimony, p 12, November 4, 2004.

[16] *See*, ER03-563-030, Stoft testimony, p. 78-79, August 31, 2004.

- In December 2003, the NY ISO filed its first annual report which noted that although capacity prices were higher than in the prior year, the prices had recently started to decline on a month to month basis. FERC, in an Order issued September 15, 2004, accepted the NY ISO's report but directed the NY ISO evaluate the cost impacts of the demand curve on customers in its next annual report due in December 2004.

As shown in the graph below, the NY ISO uses separate demand curves for each of three zones: NY State, Long Island (LI) and New York City (NYC). Each demand curve sets a target level of capacity at peak load plus reserves (using an 18% reserve requirement), but the estimated levelized cost of a peaking unit varies by zone. Payments are capped at approximately two times the cost of a proxy peaker unit for the "rest of New York", and slightly less than two times the proxy peaker price for the LI zone and the NYC zone.[17] The demand curves stop paying for capacity at 12% above peak load and reserves for NY State and at 18% above peak load and reserves for LI and NYC.[18]

The NY ISO demand curve is used to set prices for resources in a monthly deficiency auction. The deficiency auction occurs after a monthly capacity auction has occurred. Although entities are subject to the demand curve prices only to the extent that they must purchase resources in the deficiency auction, the prices in the earlier capacity auction tend to reflect the prior deficiency auction prices set by the demand curve.

Below, we show the New York ISO demand curves for each zone for the winter of 2004-2005.

[17] For the 2004-2005 winter period, the ratios are about 1.9 for NY State, 1.7 for LI, and 1.6 for NYC. The absolute values (prices) are higher in both LI and NYC, even though their ratios are less.

[18] The NY ISO graph designates the target quantity of resources as "UCAP" rather than "ICAP", or Installed Capacity. UCAP stands for Unforced Capacity; it represents an adjustment to the full quantity of MWs that a resource may be able to provide that reflects the frequency of planned and unplanned outages for that resource. UCAP values are always smaller than ICAP values. All of the proposed mechanisms reviewed in this paper make adjustments to the Claimed Capability or ICAP value of all resources to reflect their average, actual availability, or UCAP value.

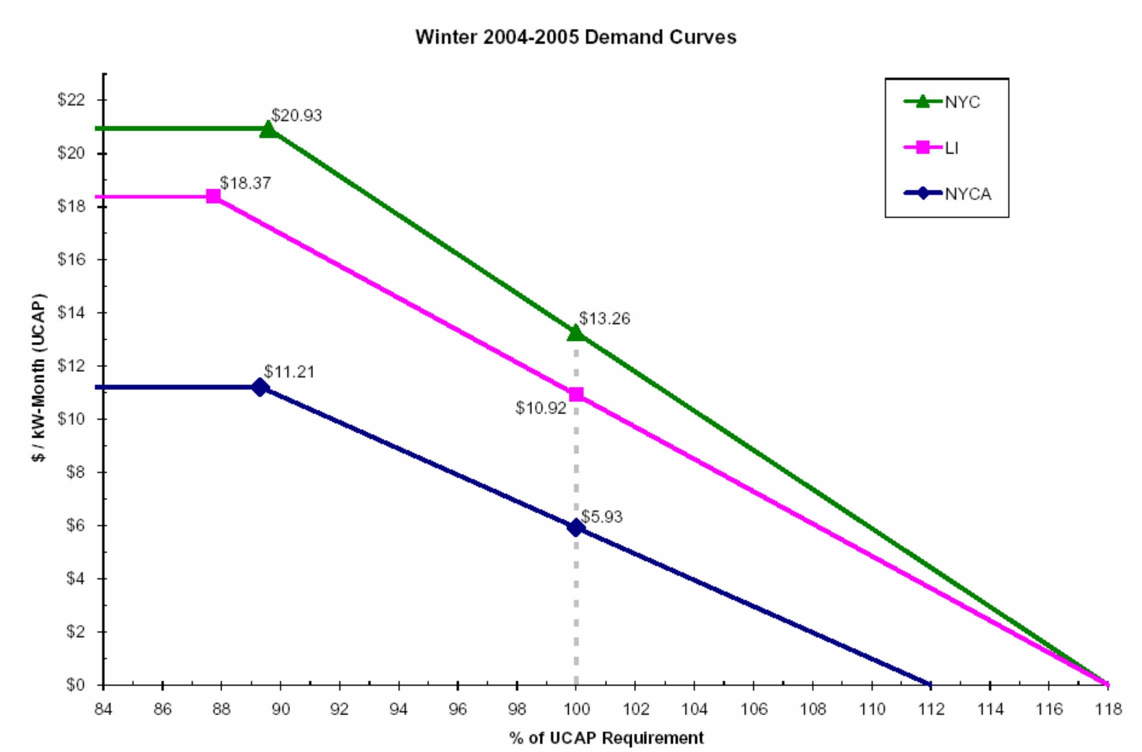

Figure 4. Proposed NY-ISO Demand Curve by Zone for the Winter 2004-2005[19]

As noted above, the NY-ISO has not determined the cost impacts of its demand curve. However, pursuant to FERC's Order this fall, the NY ISO will be evaluating the cost impacts in its annual report due to be filed in December 2004.

2. ISO NE

Capacity planning in New England has been an ongoing topic of debate. The sequence of related events thus far is as follows:

- In March of 2003, ISO filed a proposal with FERC to implement a special pricing model in chronically congested areas of the New England region.[20]

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[19] Graph from NY ISO "ICAP/UCAP Translation of Demand Curve & In-City Mitigated Unit Price Shapes" for the Winter of 2004-2005.

[20] For three years, ISO-NE had been trying to develop an alternative to its installed capacity (ICAP) market that had been implemented in 1998. Due to evidence of exercises of marker power in bids submitted into the ICAP market in early 2000, the ICAP market had become an administered market with mandatory bidding requirements. Prices in the ICAP market since 1998 had rarely cleared above 1.00 and often cleared at zero. Even thought there were market zones that had insufficient resources, the regional nature of the ICAP market produced a single clearing price of near zero for the entire region.

- In May 2003, FERC rejected the ISO's proposal, substituted its own special pricing model for those areas, and ordered ISO-NE to file a proposal by March 2004 (for implementation by June 2004) that would provide a locational capacity price signal for regions that were compensating local resources through reliability-must-run contracts and other special out-of market contracts.
- In March 2004, ISO-NE, after an extensive and contentious stakeholder process, filed a locational capacity proposal (LICAP) that utilized a "demand curve" to establish prices that was similar in theory to the NY ISO demand curve.[21]
- In early June 2004, FERC approved "in concept" ISO-NE's proposal but set for evidentiary hearing several issues related to the parameters of the demand curve.
- In late August 2004, ISO-NE filed modifications to its March 2004 LICAP proposal that changed virtually all of the parameters of its March demand curve filing, its method for determining monthly compensation values, its eligibility criteria for LICAP payments, and significant aspects of its market monitoring and mitigation rules. FERC anticipated a contested evidentiary hearing and concluded that the earliest date for an adjudicated LICAP decision would be January 2006 with implementation unlikely before June 2006.
- In November 2004, FERC issued an Order on requests for clarification and rehearing. In that Order, FERC explicitly found that the ISO-NE demand curve approach was just and reasonable and that the issues open for litigation were the parameters of the demand curve, not alternatives to the demand curve. That Order has been appealed by several parties to the Federal Circuit Court; other parties have filed rehearing and clarification requests with FERC.

Until a locational capacity mechanism is implemented, the New England zones with resource limitations will continue to compensate generating resources through reliability must run (RMR) and other special contracts that help ensure that consumers have available to them an adequate supply of electricity at all points in time. One of the unresolved issues for the two regions in New England with the most severe congestion costs (Southwest Connecticut and Greater Boston) is how to incorporate planned transmission upgrades into the ISO's LICAP proposal. It would be counter-productive to implement a pricing system for capacity resources that encouraged new entrants (based on a price signal) only to have that price signal severely undermined by new transmission projects that allow for the import of inexpensive resources from other regions in New England. Resource providers would be deceived and consumers would pay for both the transmission upgrade and the higher price signal for new resources.

[21] The ISO-NE demand curve was modeled upon the NY ISO demand curve, but also had significant differences which will be discussed below. It is also worth noting that the ISO-NE filing on March 1, 2004, failed to achieve significant stakeholder support and was heavily criticized from resource provider, load, and regulatory perspectives.

Details of the NE-ISO proposal

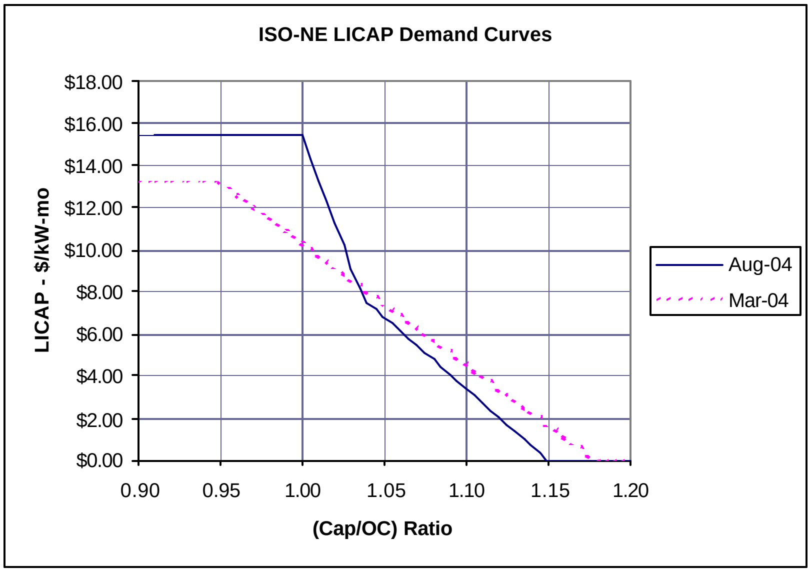

Figure 5. ISO-NE demand curves from March filing and subsequent August filing. The August filing contains a kink (Ck) at the August proxy peaker value of about $8/kW-month.

As detailed in the graph above, the ISO-NE demand curve sets a target level of capacity (Ctarget) at just over 5% of Objective Capability (OC at 1.05) for its March filing and at just under 1.04 for its August filing .[22] ISO-NE's testimony states that the target levels in both filings are set to achieve an actual available capacity of 1.054, which is the historical average of capacity resources in New England over the last 21 years.[23] This is one of the significant differences between ISO-NE's demand curve and the demand curves of New York and PJM (as well as many of the alternative demand curves discussed later in this section). Both New York and PJM set their Ctarget levels at 1.0, which represents the "peak load plus reserves" requirement (OC or IRM) of their control areas. Setting Ctarget to achieve 5% more than the "peak load plus reserves" creates a bias towards acquiring more capacity and making higher payments to resource providers (higher prices to consumers) along all points of the demand curve.

ISO-NE's proposal sets its capped price at twice the proxy peaker price (EBCC) and reaches that capped price at the 1.0 quantity of resources (100% of forecasted peak load plus reserves). The capped price value is not based on any specific analysis; it is set at a level that is believed to be "high enough to send a very strong investment signal [for new entry]."[24] By setting the capped

[22] The Ctarget (1.05) in the March filing relates to a proxy peaker cost estimate (EBCC) of $6.60; the Ctarget (1.038) in the August filing relates to a proxy peaker cost estimate (EBCC) of $7.70.

[23] *See*, ER03-563-030, Stoft testimony at 49, August 31, 2004. Stoft states that because the slope to the left of 1.037 is three times the slope to the right, that there is a bias towards "over-building" and that the actual long-term average quantity or resources will be at the 1.054 level.

[24] *See*, ER03-563-030, Stoft testimony at 15, August 32, 2004.

price at the 1.0 quantity, ISO-NE is attempting to ensure that capacity resources never go below the "peak load plus reserves" requirement; i.e., there will never be a shortage of resources.

ISO-NE's August proposal sets a "zero" value for capacity (Cmax) at a quantity of 15 percent above the "peak load plus reserves" level. This amounts to a loss of load expectation (probability that the lights will go out) of one day in 1250 years.

The August proposal also establishes five separate capacity zones. Each zone would have its own demand curve to establish prices in that zone, while each curve would have the same parameters (target level, caps, zero point, etc.). Each zone would have a quantity of resources designated as a "locational requirement," which would take into account transmission import constraints. If transmission import (or export) constraints are not binding, then the zonal price equals the "rest of pool" price. The five zones are Southwest CT, Connecticut, Boston, Maine, and Rest of Pool. The first three are import constrained, resulting in higher demand curve prices than the rest of pool (SW CT is actually a sub-zone within CT); Maine is export constrained and will have demand curve prices lower than the rest of pool.

Testimony in the LICAP litigation has identified an incongruous outcome of the ISO-NE demand curve in regard to import constrained zones. These zones are unable to use lower-priced resources from outside the zone and must rely on expensive resources within the zone. If a transmission upgrade is made to increase imports, an odd thing happens to the demand curve prices: the total cost in the previously constrained zone goes down because of the import of lower priced resources and a corresponding shift "down" the demand curve. The total cost in the zone with the lower priced resources goes up due to the shift "up" the demand curve. However, even though the total resource mix for all zones represents lower-priced resources, the total cost for all zones is higher![25] This is due to the dynamics of the demand curve (its slope.) The end result is that society as a whole pays more whenever an import constraint is relieved. This is one of the negative aspects of ISO-NE's proposal (and perhaps all demand curves), as total system costs should decrease whenever bottlenecks or constraints are removed.

Numerous parties in the LICAP litigation have estimated the cost impacts of ISO-NE's proposed demand curve. The details of some of those estimates are in Appendix E. Any calculation is complicated (in addition to the normal uncertainty about load growth and generation additions/retirements) due to the existence of numerous special contracts for units that are run for existing reliability concerns and uncertainty as to whether those contracts will be partially or fully eclipsed by the demand curve payments. There is also controversy over the capacity transfer limits between LICAP zones which, as noted above, can have significant impacts on the prices set by the demand curve.[26] Below is a table with estimates based on a model that is the same as the one ISO-NE uses to forecast the dispatch of the New England bulk power system. Additional details are in Appendix E.

[25] ER03-563-030, Pechman testimony at 30-36 and Daly testimony at 23-24, November 4, 2004.

[26] There are also transmission upgrades scheduled for completion over the next several years that will impact the capacity transfer limits between zones and the need for reliability units within zones.

Table 2. Net Incremental Cost Impact by Zone ($Millions)

	NEMA	ROP	Maine	ROCT	SWCT	TOTAL
2006	$140	$407	$68	$22	$85	$722
2007	$257	$677	$112	$100	$168	$1,314
2008	$373	$941	$156	$176	$250	$1,896
2009	$489	$1,208	$201	$252	$333	$2,483
2010	$799	$1,923	$319	$457	$552	$4,050

Source: Testimony of James Daly, Docket No. ER03-563-030, November 4, 2004, p. 14.

The table shows that costs to New England consumers would start to exceed $2 billion annually after the third year of implementation (2008). This is about the point where the demand curve reaches the estimated cost for new resource entry (EBCC) which is the long-term equilibrium point of the ISO-NE proposed demand curve. After five years, the sum of the annual costs would be about $10.4 billion dollars. $10.4 billion is sufficient to purchase at full capital cost 17,000 MWs of new resources (combustion turbines) at the estimated proxy peaker cost.[27] Purchased resources would not require any future capacity payments toward their capital cost; they would only need to recover annual operations and maintenance costs to the extent that those costs were not recovered from their energy market revenues. Certainly 17,000 MWs of new peaker units far exceeds the need for new entry in a region that currently has a peak load and reserves requirement of under 28,000 MWs and existing resources of over 30,000 MWs. Implementing a resource adequacy mechanism that could impose even half of the estimated $10.4 billion of costs on regional consumers would seem excessive and unjust when the actual resource need is so much less.

3. PJM

PJM has spent a great deal of effort trying to develop a resource adequacy proposal that addresses operational reliability issues as well as long-term capacity needs. In this paper we focus on how the proposal addresses the long-term capacity needs of PJM.

- In the spring of 2004, PJM announced a stakeholder process to review a proposal for a Reliability Pricing Model (RPM) that would address long-term resource adequacy through the use of a capacity auction that would establish prices through a demand curve and competitive supply offers.
- In June, PJM produced a whitepaper describing its proposal and began a series of stakeholder meetings to discuss, modify, and expand upon its basic concepts.[28]
- The stakeholder meetings were originally scheduled to end in late November or early December so that PJM could finalize its proposal for filing at FERC by the end of 2004. PJM announced at the end of October that it was extending the stakeholder discussion process and that it did not anticipate making a FERC filing until sometime in the first quarter of 2005.

[27] Docket No. ER03-563-030, Testimony of James Daly at 15, November 4, 2004.

[28] The first whitepaper was version 1.0; in September 2004, PJM provided a slightly revised whitepaper, version 3.1.

- PJM maintains its goal of implementing its proposal prior to the summer of 2006 (for the 2006-2007 power year), which would require a series of auctions in the fall and winter of 2005.

Unlike ISO-NE's monthly market, PJM's RPM proposal is based on an annual auction for capacity resources four years in advance of its target year, or planning year. Supply offers would be stacked up to create a supply curve that would intersect with an administratively set demand curve. Winning offers would be assured of payment in the planning year (four years into the future) at the auction clearing price. The precise parameters of the PJM demand curve have not been established, but the stakeholder group has been discussing a demand curve that sets a target equilibrium point at the cost of new entry (a proxy peaker price) for the peak load and reserve requirement. Beyond the reserve requirement, the capacity price descends rapidly to near zero at ten percent above the target quantity of resources. Similarly, above the equilibrium point, the capacity price ascends rapidly to a maximum price a little less than two times the proxy peaker cost, when the total capacity is about five percent below the target quantity.

PJM established its demand curve parameters by estimating the "value of lost load" (VOLL) for consumers. Using several historical studies, PJM developed an average value for all customers (residential, commercial, and industrial) and then applied that value to various levels (quantities of resources) of reliability. PJM added those values to the peaker unit price to establish the price points for both surplus and capacity scarcity situations.

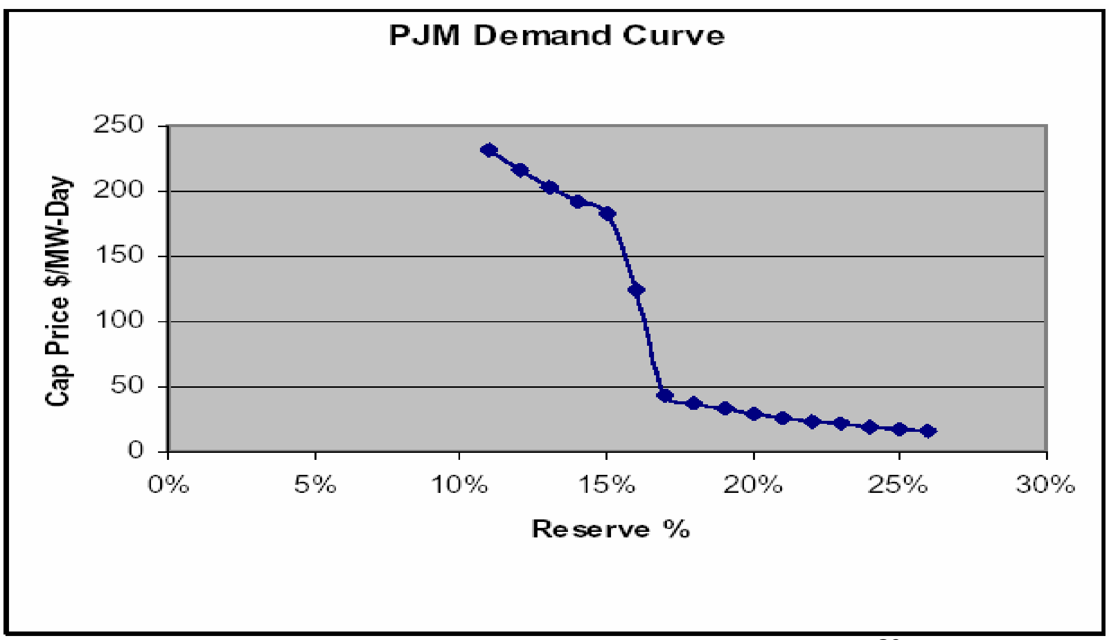

Figure 6. PJM Demand Curve from Sept. 2004 PJM whitepaper[29]

This demand curve (above) is much steeper than either the NY ISO or ISO-NE demand curves. It is also uses a proxy peaker value that is about two-thirds of the values used by IS0-NE and NY

[29] Note that 16% Reserve in this graph corresponds to an OC value of 1.00 in the ISO-NE demand curves and that 100 $/MW-Day corresponds to 3.0 $/kW-month)

ISO.[30] In the stakeholder process, PJM has discussed several modifications to its original demand curve. One that has been adopted is to shift the target level of capacity, and therefore the proxy peaker value, to 15% above peak load, rather than the current 16%. This reflects both a small conservative assumption for a four-year advance auction (to avoid over-purchasing) and an anticipated change in PJM's planning criteria from a 16% reserve margin to a 15% margin.[31]

PJM has a unique feature to its resource adequacy proposal that neither NY ISO nor ISO-NE use. PJM is considering cost-capped bids to create a supply curve that will intersect with its demand curve. A cost-capped supply curve will help to limit the extent to which resource providers can profit from the exercise of market power. This feature is still being formulated through the stakeholder process; it may apply only to bids in constrained regions.

PJM has recently completed several simulations of its demand curve. The most complete simulation is for the planning year 2008-2009. Figure 1 at the beginning of this report illustrates the basic results with the clearing price for all resources at approximately $65 per MW-day. In the graph below we look at what happens if the demand curve is shifted as a result of changes in load over time.

The Supply and 2008-09 Demand curves are from a PJM presentation at the RAM Stakeholder Working Group on November 9, 2004[32]. We have added lines representing the current estimated capacity price ($15 per MW-day) and a second demand curve representing a 3% growth in load that brings the marginal cost on the demand curve up to that of a new resource. We have not modified the supply curve since significant additions of new resources are not expected until the market price reaches that of new capacity at 125 $/MW-Day.

[30] For comparison purposes, PJM uses a proxy peaker value of about $4.75/kW-month compared to ISO-NE's value of $7.70/kW-month (for the ROP zone) and NY ISO's value of $6.00 (for the Rest of NY zone).

[31] PJM is evaluating several alternatives to its initial demand curve. Some of the preliminary modeling suggests that a demand curve that sets EBCC at 1.01 on the demand curve (IRM plus 1%, or 16% above peak load) may produce an acceptable level of reliability at a reasonable cost. *See*, PJM RAM Stakeholder Working Group, Presentation 1, December 9, 2004.

[32] PJM RAM Stakeholder Working Group, Presentation 1, Nov 9, 2004. Numerical values are interpolated by Synapse from the presentation graph since the numerical data was not available.

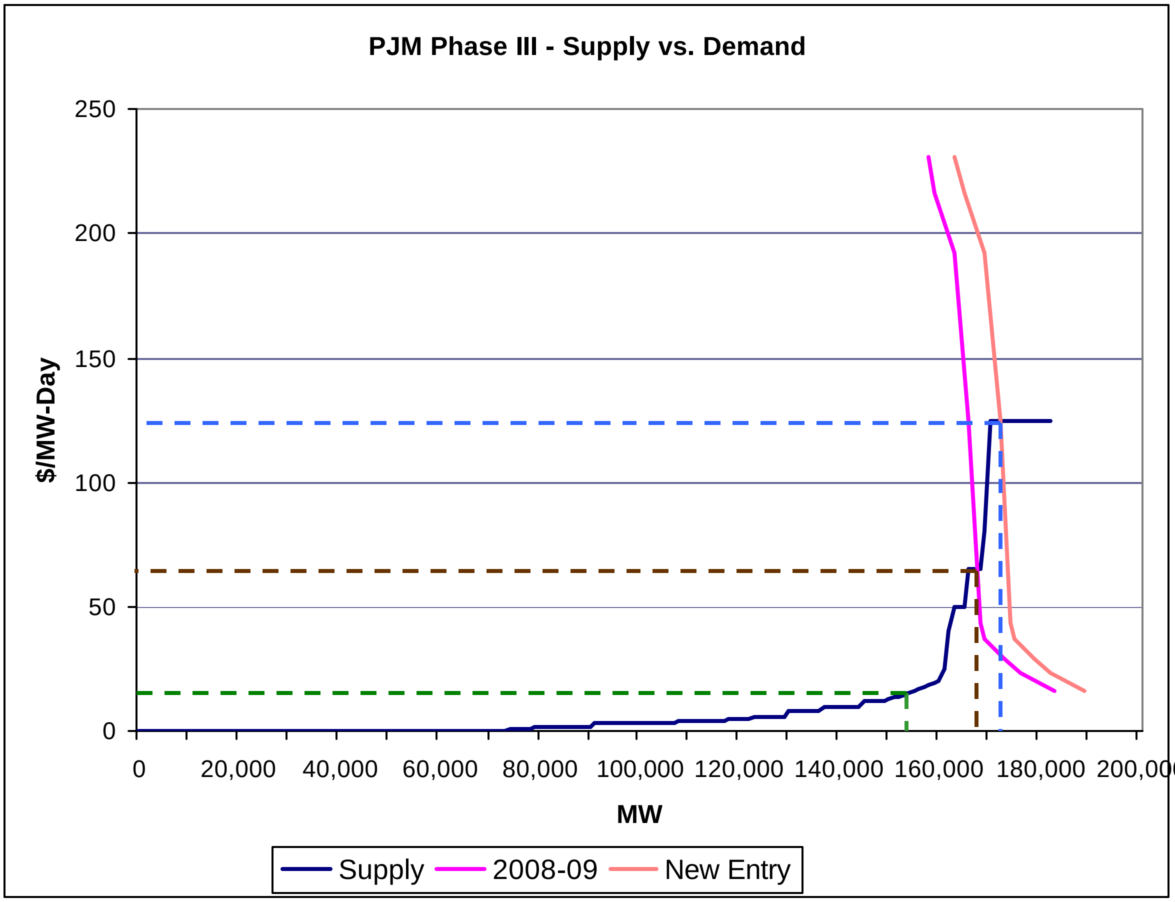

Figure 7. PJM Capacity Supply and Demand Curves

The areas within the dashed lines represent the relative costs under various conditions. For example, the total area within the second (brown) rectangle represents the total cost in 2008-2009 if **all** capacity (new and existing) were paid the marginal cost of 65 $/MW-day ($4,000 million). The area under the dark blue supply curve up to the vertical descending line of that same rectangle represents what is actually needed (about $350 million). The table below quantifies some of these impacts.

Table 3. Illustrative Capacity Costs in PJM at Different Demand Levels

Period	Current	2008-09	Future	Unit
Threshold Demand Level	154,000	166,000	172,000	MW
Capacity Intercept Level	154,000	168,000	172,000	MW
Intercept Price	15	65	125	$/MW-Day
Incremental Capacity		12,000	6,000	MW
Supply Curve Cost	$247	$355	$521	Million$/Year
Incremental Cost		$108	$166	Million$/Year
Incremental Capacity Cost		$21	$114	$/MW-Day
Single Market Price Cost	$843	$3,986	$7,848	Million$/Year
Incremental Cost		$3,143	$3,862	Million$/Year
Incremental Capacity Cost		$615	$2,645	$/MW-Day
Demand Curve/Supply Curve	3.4	11.2	15.1	

There are reasons why the "supply curve cost" may understate the compensation that should be provided to resource providers. PJM's cost-capped offers reflect the marginal costs to provide an additional MW of the resource and do not account for any contribution to fixed costs (capital) nor do they incorporate opportunity costs (the value of a MW sold bilaterally or into another control area). The value of $15/MW-Day that we use for the current value of capacity would quantify that difference in today's market at three-times the cost-capped value. However, when the demand curve starts to set prices in the 2008-09 power year, the difference increases to eleven-times the cost capped value. When the demand curve reaches the goal of the proxy peaker entry price, the difference is fifteen-times the cost-capped value.

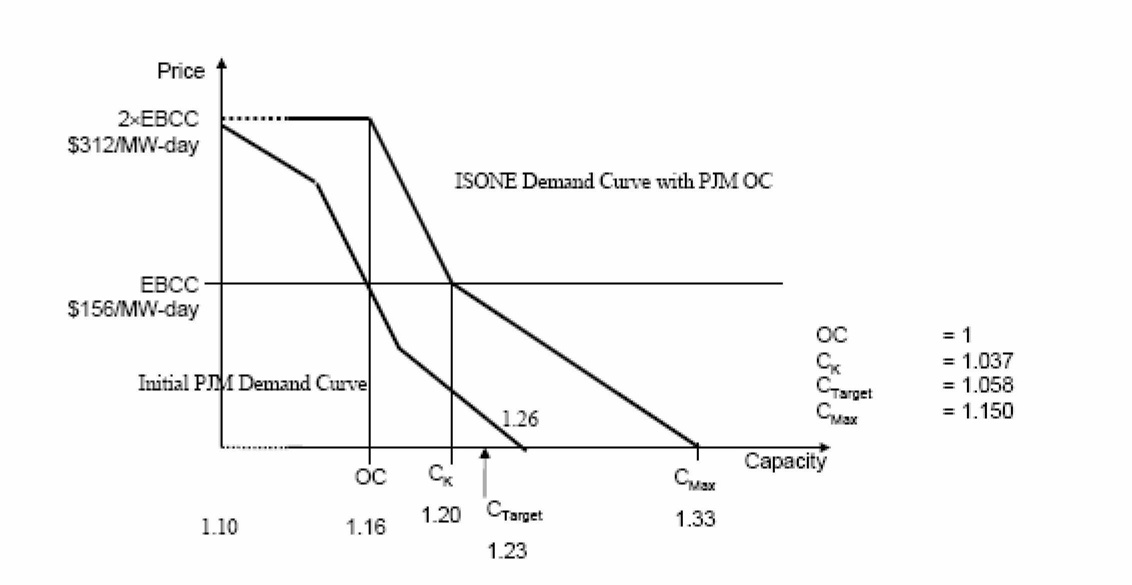

Figure 8. ISO-NE Demand Curve with PJM OC

PJM is considering adjustments to its demand curve. Above is a graph that shows how PJM values for EBCC and OC would create a demand curve with ISO-NE's other parameters of Cmax, price cap (Cmin) and a kink (Ck).

PJM has noted that the most dramatic cost changes come from shifting the whole curve right or left (changing EBCC from 1.16 to 1.20 on the x-axis, above). With the modified PJM demand curve, the price at OC or IRM (1.16) would be twice the price ($312/MW-day) of the original curve ($156/MW-day). Similarly, the $65/MW-day price from the 2008-2009 curve described earlier would translate to about $150/MW-day with the modified PJM demand curve. The total demand curve costs in the table associated with the two demand curves in the 2008-2009 graph would double. Changing the PJM curve to the ISO-NE parameters would significantly increase costs at all points on the demand curve for equivalent quantities of capacity

A second modification that PJM has considered is to adopt a more gradual slope to its demand curve. A more gradual slope provides two benefits. First, it reduces the incentive to try to exercise market power through economic or physical withholding (reduced quantities do not push prices "up" the demand curve as quickly). Second, the revenues to resource providers are less volatile (more price points are "near" the proxy peaker price rather than at high or low extremes). [33]

[33] PJM has contracted with Johns Hopkins University to model alternative demand curves in an effort to learn more about the reliability and cost impacts of various curves. Preliminary results are just becoming available in December 2004. Complete results should be available in early 2005.

4. Other demand curve proposals

Below is a graph of all the demand curve proposals filed in response to ISO-NE's FERC litigation. Each curve makes adjustment to the ISO's parameters discussed earlier in this section. For comparison purposes, some adjustments were made to the actual filed curves and all the curves are applied to the SWCT LICAP zone. The composite was developed by the CT Coalition.[34]

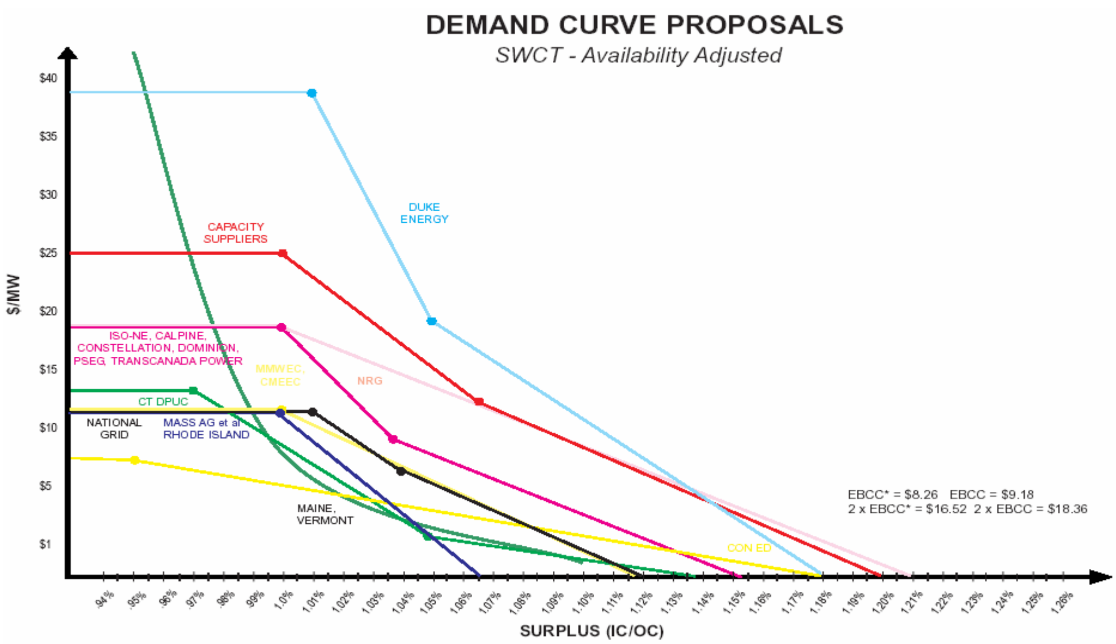

Figure 9. Demand Curve Proposals

These demand curves (above) all utilize the basic construction points of ISO-NE's demand curve described earlier. The differences are the assumptions of where to set Ctarget, Cmax, the capped price, EBCC, and any kinks. For example, the Duke Energy curve (light blue at top) sets EBCC (the proxy peaker value) at about $19 per kW-month, significantly above the ISO-NE demand curve (magenta in the middle) value of $9.18. Duke Energy's capped price is 2 times EBCC, or about $38 per kW-month. In addition, Duke Energy set's Ctarget at about 5.5 percent above Objective Capability (OC, IRM, or peak load plus reserves) while ISO-NE sets Ctarget at 3.8 percent above OC. Duke Energy's Cmax is set at 18 percent above OC, compared to 15% for ISO-NE.

Alternatively, the Mass AG/NSTAR coalition demand curve (royal blue near bottom) sets its capped price at 1.2 times ISO-NE's EBCC value of $9.18 for a capped price of about $11. Most

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[34] CT Coalition consists of Connecticut Department of Public Utility Control, Connecticut Office of Consumer Council, Connecticut Attorney General, and Southwest Area Commerce and Industry Association of Connecticut. Connecticut as a whole and southwest CT in particular face significant impacts from the ISO-NE LICAP proposal.

significantly, the Mass AG/NSTAR coalition Cmax is 6.5 percent above OC, compared to ISO-NE's value of 15 percent. The 6.5 percent value represents a "loss of load expectation", or LOLE, of one day in 100 years which is ten times the current reliability standard of one day in ten years. As stated earlier, ISO-NE's value of 15 percent above OC represents an LOLE of one day in 1250 years.

The other demand curves represented in the composite graph above represent various alternative assumptions about where to set the cap, the EBCC value, Ctarget, and Cmax. A few add kinks that produce additional variations for particular reasons. Most of them fall within either the parameters of the Duke and MassAG/NSTAR coalition demand curves. In the appendices to this report, we examine in greater detail both the MassAG/NSTAR coalition (Appendix B) and the CT DPUC coalition (Appendix C) proposals because of some of the unique variations they propose. The demand curve parameters have enormous consequences on prices and ultimate costs. As noted in the PJM example above, shifting the entire curve right or left a few percentage points can double or halve the costs to consumers (as determined by the rectangle created by the intersection of supply and demand).

5. Demand Curve Summary

Recently, a great deal of emphasis and time has been put into demand curve theory and practice in terms of satisfying future capacity. However, demand curves contain many fundamental flaws that undermine the goals of maintaining reliability and minimizing costs to customers. Below, we summarize some of our findings:

- Demand curve mechanisms impose substantial new costs because they require new entry payments (on average) to all capacity resources regardless of the revenue requirements (forward costs) of specific resources. These new entry payments are particularly inappropriate for resources that have already recovered most or all of their capital costs through cost of service regulation. Requiring consumers to pay twice for the same resource is difficult to justify, and may be illegal, under the Federal Power Act. The issues become much more complex when considering resources that have been sold due to divestiture requirements. In some situations, consumers may have received direct compensation from the sales or indirect compensation through specific rate reductions. Each divestiture sale may need to be separately analyzed to determine the overall net benefit or cost to consumers.
- Demand curve approaches need to reconcile earnings from energy and ancillary services markets with the capacity payments they produce. This is because even a proxy peaker unit that runs only a limited number of hours each year is likely to earn "excess" revenues during those hours, due to the relatively high energy prices in the hours that it operates.[35] The NY ISO does not make any adjustments for

[35] For example, a combustion turbine that operates only during times of system emergencies may have a bid price of $150 per MW based on its marginal cost of operation (fuel cost and avoidable O&M), but may receive payments based on a clearing price of $500 to $1,000 per hour due to the emergency. The dollars in excess of its bid price are a contribution to its fixed costs and should be deducted from its capacity payments (which are intended to cover annualized fixed costs).

energy and ancillary services revenues. The ISO-NE proposal in March made an explicit reduction based on an estimate of "excess" energy market revenues that a proxy peaker would earn; ISO-NE's August proposal replaced the March ex-ante reduction with an ex-post reduction based on an estimate of "excess" energy market revenues earned by a proxy peaker in the prior month. PJM is still developing its adjustment and has committed to properly account for the energy and ancillary services revenues from a proxy peaker resource.

- Demand curve mechanisms, while setting prices at the cost of new entry, may not attract any new entrants due to the uncertainty created by annual one-year auctions. ISO-NE's proposal further compounds this uncertainty by establishing an "after the month" determination of what units qualify for the new entry payments and by varying the payments themselves. It is hard to see how a demand curve "revenue stream" with its substantial uncertainty will produce a balance sheet that can attract new investment or secure a bank loan. The most common complaint today from resource providers is that the financial community will not provide loans or investment capital due to the perception that future revenue recovery by new resources is too uncertain. Without long-term financing, new resource projects are unlikely to be initiated.
- Small changes to a demand curve can have substantial impacts on prices and ultimate costs. Most of the demand curve parameters are administrative determinations, not market based. Each of those determinations will require periodic adjustments that are likely to involve contentious and possible litigated proceedings (e.g., setting the proxy peaker cost, setting OC/IRM, setting Cmin, Cmax, and Ck/Ctarget)
- Demand curves create market power concerns and risks. The steeper the slope of a demand curve, the more incentive a resources provider has to withhold even small amounts of capacity to create a dramatic increase in revenues. Market monitoring of resource providers bids, particularly in load pockets, will probably need to be more extensive in these new capacity markets than in the existing energy markets. Plus, existing resources will have strong incentives to block the entry of new resources due to the overall reduction in demand curve prices that additional resources cause.

C. Alternative Approaches

While most of the discussion to date has been about demand curves other options do exist. These other options are explained below.

1. Rational Procurement – IRP approach

A traditional approach for ensuring resource adequacy is planning. Integrated resource planning (IRP) processes have been widely used over the last twenty years across the United Sates. IRP provides a comprehensive assessment of loads, resources, and transmission capability to determine a "least cost" mix of generation, demand, and transmission investments. IRPs were developed by vertically integrated electric companies with review and approval by state regulatory agencies. With an approved IRP, a utility could make investments in generation, demand, and transmission projects with a reasonable expectation of recovery of its costs. The recent implementation of retail choice and wholesale electricity markets in many regions of the country has also led to the divestiture of generation resources by transmission/distribution entities and the transfer of load responsibilities to competitive suppliers.[36]

With an IRP approach, the entity responsible for ensuring resource adequacy (traditionally the vertically integrated utility that had the load/service obligation; today it could be the distribution company or the ISO/RTO) would issue RFPs for specific projects such as a new generation unit, a purchase power contract, an energy efficiency program, or a transmission upgrade. The successful bidder would be paid a pre-determined amount (its bid) over a period of time (based on the contract) and the entity that issued the RFP would bill the costs to retail consumers through a tariff rate.

IRP, and other traditional utility investment processes, can be characterized as "central purchase" options. An entity makes resource purchases on behalf of loads and then bills the costs to those loads. Prior to IRP, there was an historic tendency to over-purchase resources and pass unnecessary costs on to consumers. It was this historical trend that encouraged many jurisdictions to adopt more comprehensive planning processes such as IRP that considered the least cost solution of demand side, supply side, and transmission investments. It is interesting to note that the restraint on over-purchasing resources that developed with IRP was followed by utility company interest in divesting generation and allowing customer retail choice. As part of the transition to retail choice a utility's "stranded costs" from past resource purchases had to be explicitly reconciled.

2. New and Old Generation Distinction

Some agree that attracting new market entry will require a capacity payment compensation system equivalent to a "proxy peaker" capacity payment; they balk, however, at paying that proxy peaker capacity payment to all resources. They maintain that most existing generation has already recovered significant contributions to capital costs (based on past years of operation), that non-peaker resources continue to recover capital costs from energy and ancillary services markets, and that proxy peaker capacity payments are an unjustified windfall.[37] To address this concern, one could distinguish between existing and new units and make payments based on either unit-specific cost information (similar to what is done with reliability-must-run, or RMR, contracts) or develop compensation formulas for years or hours of operation of a generic plant of a specific fuel-type (gas, coal, nuclear, hydro, etc.) and operation type (base load, intermediate, peaker).

[36] Some jurisdictions have required divestiture of generation assets as a pre-condition for retail choice; other jurisdictions have encouraged divestiture. In many regions, consumer-owned entities (cooperatives and municipals) have been allowed to remain vertically integrated while investor-owned entities have divested.

[37] *See*, ER03-563-030, Daly testimony at 33-35, November 4, 2004.

A major issue under any type of "new versus old" compensation system is how to classify resources. If a unit is retired and then comes back into service, can it be classified as new? What about a resource that goes through a bankruptcy proceeding or that is sold to a new owner? Can a resource that is physically located outside the control area but can qualify to sell capacity into the control area be classified as a new unit? If formulas based on resource fuel-type and operating characteristics are used, how will those formulas be developed? How often will they be updated? Will resources be able to move between formulas based on changes to their operations and as they age? Alternatively, if specific unit revenues are utilized, how will that information be collected and evaluated? How often will it be updated? Will compensation be automatically linked to various fuel indexes to capture fluctuations in fuel prices?

Some critics raise equity issues. They argue that all megawatts are equally valuable during a system peak so the compensation mechanism should also be the same. Others raise concerns about the burdensome administration of compensation mechanisms based on resource characteristics. For others, such administrative schemes are rejected out of hand because they are not "market based."

There are less complex ways to resolve the "new versus old" distinction. New resources could qualify for proxy peaker payments; old resources could utilize the existing ICAP mechanisms and, if those are insufficient, apply for RMR compensation. Another alternative is to maintain the new versus old distinction for an explicit period of time as part of a phase-in or transition mechanism, which is discussed in more detail below.

3. Pay as Bid

Some have suggested that "pay as bid" auctions are a "market based" mechanism that can be used to create price discrimination among resource types.[38] Pay as bid works as follows: rather than paying all winning bidders the "clearing price" (the highest price paid to the last winning bid), all winning bidders would receive their bid prices. A pay as bid approach could use the same auction or demand curve system proposed by the ISOs (see earlier discussion). Price discrimination would occur, and the total cost to consumer would be less, if resource providers bid at or near their marginal capacity cost.

However, there are concerns that resource providers in "pay as bid" auctions do not bid in the vicinity of their marginal capacity cost; instead, they bid at higher levels that approximate their best guess or estimate of the last accepted bid. This kind of information is fairly well known to participants in electricity markets. Under this assumption, a pay as bid mechanism may not achieve any significant price discrimination or total cost savings. In fact, many economists maintain that pay as bid auctions also result in overall inefficiency because some of the "lower cost" resources will price themselves out of the auction by incorrectly estimating the last accepted bid.

[38] *See*, P. Klemperer, *Auction Theory: A Guide to the Literature*, Journal Economic Surveys, 1999, 13 (3), at 227-286. In an Electricity Journal Article, FERC economist Richard O'Neill notes that a "capacity price may be discriminatory" (as compared to energy markets where single clearing price auctions are preferred). EJ June 2004, p. 59.

One way to address both the total cost savings issue and the potential inefficiency of a pay as bid auction is to require resource providers to bid under a cost-cap. As with the approach for new and old resources discussed above, the cost-cap can be based on generic resource compensation formulas or specific individual resource costs. The same issues on classifying new and old resources regarding how to determine the formulas or collect individual unit information would apply under a cost-cap mechanism.

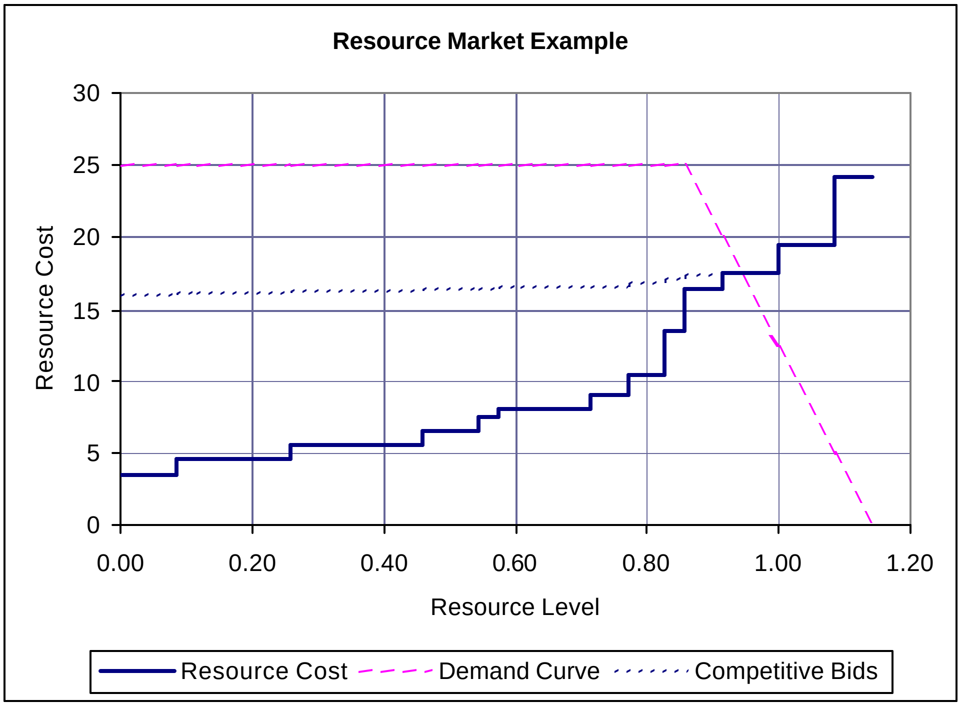

Figure 10. Example of Resource Market

This graph shows a cost-capped pay as bid mechanism (the stair-step blue line) where resources bid their relative marginal costs. Some resources receive high prices and some receive lower prices. New entrants, if selected, would receive their new entry costs, assuming that they bid at that level. The dotted line shows how uncapped bidding might occur, where each resource tries to guess what the highest accepted bid would be and make their resource bid at or below that estimated bid. Uncapped bidding can produce results similar to a single clearing price auction.

4. Cost-capped bids and a segmented auction

A third way to achieve price discrimination among capacity resources (in addition to "new v. old" and "pay as bid") is to conduct the capacity auction in discrete segments. Appendix D provides a detailed example of how such an auction could function. In brief summary, assume that there are four auctions, each for 25% of an estimate of future capacity. If all resources are required to bid at cost-capped prices, the first 25% of the capacity resource would clear at a relatively low price, the second 25 % would clear at a higher price; the third 25% would clear at a still higher price; and the final 25% would clear at the proxy peaker price (because the final 25% would include new units).

Based on the amount of fully depreciated resource units, the first 25% may clear close to zero. Over time, the last 25% would be comprised of all "new" units that qualify for the proxy peaker cost-capped bid. At that point, the third 25% segment would start to clear at the proxy peaker price, also. Eventually the second 25 % segment would clear at the proxy peaker price. The first 25% segment may never clear at the proxy peaker price due to some units fully-recovering their capital costs over time and being cost-capped at low values.

In order to provide a more secure price signal for new units, each 25% segment could be for a four-year period. Each segment could also be auctioned in a staggered (yearly) sequence to achieve overall portfolio stability. As long as the total capacity procured is above the estimate of future peak load plus reserves by 5-10%, a new entry resource will have a high likelihood of selection (and set the clearing price) for the last 25% segment.

As with the "new v. old" and "pay as bid" alternatives, a segment auction faces the same issue regarding cost-capping of bids and mandatory biding rules

Table 4. Segment Auction Results

	Segment 1	Segment 2	Segment 3	Segment 4	Total	
Capacity (MW)	42,000	42,000	42,000	42,000	168,000	
Capacity Price ($/kW-mo)[39]					Average	Annual Cost (M$)
Supply Curve	0	0.15	0.30	1.98	0.61	$1,225
Option 1	0.50	0.65	0.80	4.75	1.86	$3,377
Option 2	1.00	1.15	1.30	4.75	2.05	$4,133
Demand Curve	4.75	4.75	4.75	4.75	4.75	$9,576

The table above shows the estimated costs of a segment auction with certain assumptions. The first line shows the costs based on the current PJM supply curve. Note that the first 25% segment clears at zero and the next two segments clear at 0.15 and 0.30. Because these low clearing prices may not capture legitimate costs (such as opportunity costs or contribution to return on investment), a segmented auction approach could establish floor prices to be added to each segment that clears below the cost of new entry. Option 1 shows the costs with floor prices at $0.50/kw-month for the first three segments and the fourth segment set by new entry. Option 2 shows the cost with floor prices at $1.00/kW-month for the first three segments and the fourth segment set by new entry. The Demand Curve line shows the costs if all segments were paid the PJM new entry price (EBCC of $4.75/kW-month).[40]

Over time, as more and more new entrants come in, each segment will clear at or close to the cost of new entry. What a segmented auction achieves is a more gradual transition to the Demand Curve clearing price of $4.75/kW-month while paying existing units their going

[39] For comparison purposes, a capacity cost of 1.00 $/kW-month is equivalent to 33 $/MW-day.

[40] The EBCC is the full cost of a new entry not adjusted for inframarginal revenues. PJM has considered using a $20-30/MW-day reduction from the proxy peaker levelized cost of $156/MW-day as the average annual value of inframarginal revenues. Some of the other PJM materials used in this paper show graphs with the reduction; most use an EBCC value of $125/MW-day

forward costs during the transition. For a more detailed analysis of a segmented auction, see Appendix D.

5. Inframarginal revenues adjustment for existing units

A fourth way to "discriminate" between resources for capacity payments is to adjust their capacity payments after-the-fact based on the total revenues earned.[41] Under this mechanism, all resources would bid to supply capacity resources and would be selected through an auction or demand curve process based on their bids. All resources would receive a "single clearing price" based on the highest accepted bid. However, each resource would have its actual payment (monthly or annual) reduced by the quantity of revenues it earned above its marginal energy costs. For two extremes, consider a large fully depreciated base load plant and a new, small peaker. The large base load plant might earn "inframarginal" revenues (revenues above its energy and short run costs) that closely approximate its annual capacity payments; this unit would receive a very small capacity payment. The small peaker plant might earn almost no inframarginal revenues and would receive a very high capacity payment.

While this alternative avoids the need to cost-cap bids, it still requires the collection of data from each resource unit in order to calculate the quantity of inframarginal revenues. That data collection process and the calculation formulas to determine revenues would undoubtedly create some controversies. It might simplify matters to use generic unit formulas for specific resource types, although then the controversies would probably focus on how specific resources qualified, or did not qualify, for specific generic categories.

There would also be issues as to why "efficient" units (however they may be defined) should be treated the same as inefficient units; that is, efficient units would have larger inframarginal revenue streams than inefficient units. This might be another reason to establish "generic" categories that reflect an average efficiency. Ultimately, all of these adjustment and reconciliation mechanisms would have to meet the "just and reasonable" standard of the Federal Power Act.

6. Explicit phase-in to lower costs

There appears to be a general acceptance that in order to ensure long-term resource adequacy, some mechanism needs to be developed to pay new entrants the proxy peaker capacity cost over the financial life of the resource. Whether that proxy peaker value is 4, 8, 12 $/kW-month or more, can be debated; but the goal of providing that compensation value to new entrants has not been seriously challenged. Given that all three northeast ISO markets are currently comprised of resources that are <u>not</u> new entrants, there is a fundamental transition issue. Whatever mechanism, with or without tweaks, is selected, there may need to be an explicit phase-in to soften the "rate shock". For example, the ISO-NE proposal will add $3 billion annually to the current $8 billion (est.) wholesale power market. PJM's proposal will add about $6 billion to the

[41] This option is different from the adjustment discussed in Section B of this paper in regard to an adjustment to a demand curve based on the energy and ancillary services revenues of a proxy peaker. In this formulation, separate and specific adjustments for energy and ancillary services are made for each resource.

current $20 billion (est.) market. While the demand curves may soften the impact due to current excess capacity, withholding capacity could drive costs up quickly.

One way to accomplish the transition is to set a starting point (today) for compensation and a target goal (future) which might be the proxy peaker cost estimate or 10% above that price. Determine the number of years for the transition, which may be influenced by how soon new entrants are needed, and connect the two points with a straight line. Although not a very elegant solution, it has some practical advantages: it is simple to draw and easy to understand! If particular resources necessary to maintain reliability were unable to earn sufficient revenues to avoid retirement, they could apply for RMR compensation or be compensated through a "backstop" RFP mechanism.[42]

One example based on ISO-NE's demand curve and the New England capacity requirements is shown below. In the example, we assume a starting value of $1.00/kw-month for all capacity in year one. We then increase the value on a linear basis over the next ten years to reach a value of $8.00/kw-month. We also increase the capacity on a linear basis each year, starting at 30,000 MWs in year one and increasing to 35,000 MWs in year ten. In this example, $8/kw-month is used to represent the proxy peaker entry cost in year ten.

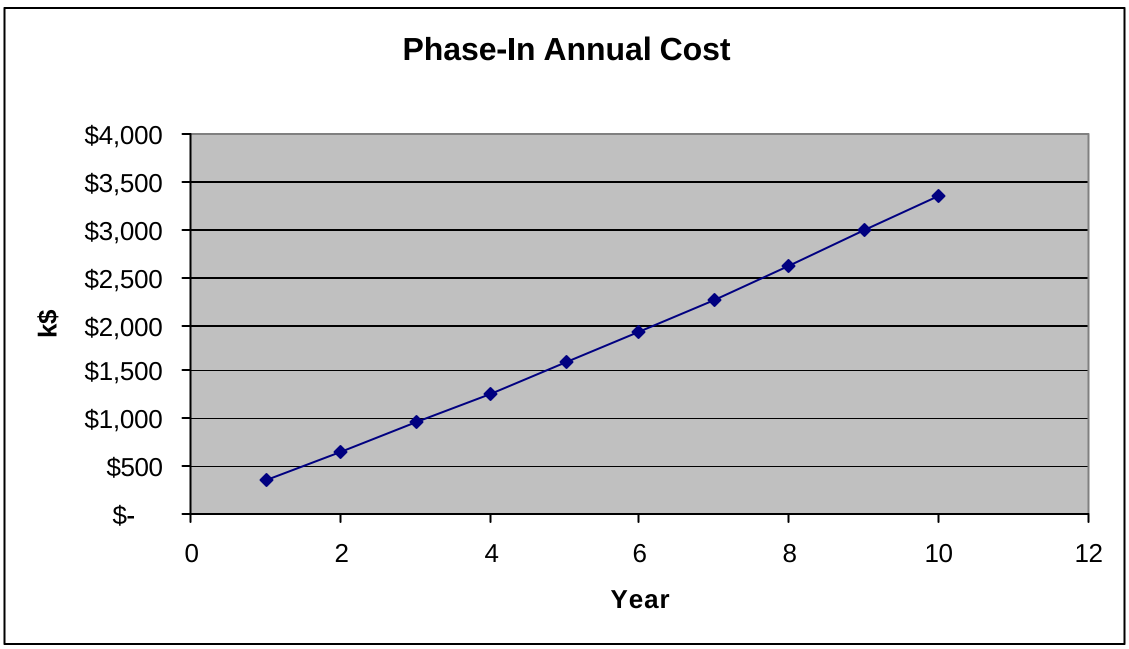

Figure 11. Phase-In Annual Cost

The table below shows the annual capacity costs from a linear transition mechanism. The costs increase gradually each year until they reach a proxy new entry value of $8/kw-month in year ten. New entry may occur well in advance of year ten if resource providers are willing to earn

[42] PJM is considering a "backstop" mechanism in its RAM Stakeholder Working Group discussions. *See*, PJM RAM Stakeholder Working Group, Presentation 2, December 9, 2004.

slightly less than the new entry value for a few years in order to be in place when the new entry price is reached. For a comparison, ISO-NE's demand curve proposal will reach the $8/kW-month level four years after implementation (2009).[43] An explicit transition mechanism such as this does not resolve any of the underlying problems with ISO demand curves discussed earlier. It is merely a means of implementing the cost impacts more gradually.

Table 5. Cost of ISO-NE Demand Curve Proposal with New Entry

Year	Amount (MW)	Price ($/kW-month)		Monthly Cost		Annual Cost ($1000s)		Annual Cost Increase ($1000s)
1	30,000	1.00	$	30,000	$	360		
2	30,556	1.78	$	54,321	$	652	$	292
3	31,111	2.56	$	79,506	$	954	$	302
4	31,667	3.33	$	105,556	$	1,267	$	313
5	32,222	4.11	$	132,469	$	1,590	$	323
6	32,778	4.89	$	160,247	$	1,923	$	333
7	33,333	5.67	$	188,889	$	2,267	$	344
8	33,889	6.44	$	218,395	$	2,621	$	354
9	34,444	7.22	$	248,765	$	2,985	$	364
10	35,000	8.00	$	280,000	$	3,360	$	375

7. Reliability option

Carl Pechman and Miles Bidwell filed testimony in the New England LICAP litigation that proposes an alternative based on a three-year-in-advance auction for a "reliability option" (RO) that could be exercised in real-time.[44] They propose that the auction would be run with a "descending clock" to achieve the most competitive price for a pre-determined quantity of resources for a particular year. Offers would be made on a per-MW basis. A strike price would be established for each locational energy market in the particular year in real-time and published in advance of the auction. The strike-price would be set at the marginal cost of the most expensive unit in the local market (indexed for fuel risk). If the local energy market clearing price exceeded the strike price, resources that cleared the auction and are being compensated in the energy or reserve markets, the resource provider pays any revenues in excess of the strike price to the ISO. If the resource provider is not being compensated in the energy or reserve markets, the resource provider pays the entire spot price to the ISO.[45]

This proposal has several features that are different from the other alternatives discussed above. First, the establishment of a strike price, in advance of the auction, allows resource providers to adjust their offers in anticipation of an opportunity to earn some inframarginal revenues. Second, by requiring resource providers to return any inframarginal earnings <u>above</u> the strike price, the RO proposal provides an immediate, specific, automatic adjustment that other

[43] *See*, ER03-563-030, Daly testimony at 14, November 4, 2004.

[44] See, ER03-563-030, Pechman testimony at 79-111. Filed on behalf of Connecticut Department of Public Utility Control, Connecticut Office of Consumer Council, Connecticut Attorney General, and Southwest Area Commerce and Industry Association of Connecticut ("CT Coalition").

[45] The resource provider may also be assessed a penalty for "not performing", although the structure for determining this penalty is not specified and the testimony states that the penalty in some circumstances may be set at zero.

proposals address after-the-fact on either a generic or unit specific basis. Third, the descending clock auction provides a competitive process for resource providers to re-allocate their offers to zones with the highest prices. And fourth, the descending clock auction provides a competitive process to purchase a sufficient, but not excess, amount of capacity.

This proposal has many of the same features that ISO-NE has used in its Forward Reserve Market: the advance auction that creates a call option; the use of a strike price to restrain anti-competitive behavior; and a penalty mechanism for non-performance.[46] This alternative has many promising features that deserve more detailed scrutiny.

D. Comparisons

In evaluating various resource adequacy proposals it is useful to have a common set of evaluation criteria. Some of the most import criteria include:

- Term of certainty
- Payment to new capacity resources
- Payment to existing capacity resources
- Total annual cost of capacity payments
- Market power implications.

See the table below for a summary of how each capacity approach fairs under such criteria. This table is based on the descriptions of the various proposals and options in this report and is time sensitive. The ISO-NE demand curve proposal of August will almost certainly change due to the FERC litigation process that will continue through the spring of 2005. The PJM demand curve proposal is changing on a weekly basis as PJM conducts further simulations and testing. We also make certain assumptions about some of the alternative proposals (such as capping all bids in the "pay as bid" and "auction segments" alternatives). We have selected these options and made calculations about their costs for comparison purposes; we do not claim that these numbers represent the actual costs that any of these options would actually produce. The "Total Annual Cost" is based on the EBCC for the demand curves and the high bid or segment at EBCC for the alternatives. There has been no reduction for other market revenues for any of the options.

In order to have a meaningful discussion about options, we have to find a basis for comparing the alternatives. The table below is a start.

[46] *See*, Joint NEPOOL-ISO filing, September 8, 2003, and FERC Order, November 14, 2003, in Docket No. ER03-1318-000.

Table 6. Comparison of various approaches for meeting capacity requirement.

Approach Name	Basic Description	Term of certainty	Pays EBCC to New Capacity	Pays EBCC to Old Capacity	Total Annual Cost*	Limits Market Power
NY ISO	Auction & Demand curve	Month	Yes, from the start	Same time as new capacity	$2.5 billion	No
ISO NE	Demand curve	None	Yes, in a few years.	Same time as new capacity	$2.6 billion	No
PJM	Demand Curve	1-year (future)	Yes, in a few years	Same time as new capacity	$7.8 billion	No
MassAG NSTAR Coalition	Demand curve for new only	None	Yes, but more slowly than ISOs.	No	Small fraction of ISOs' costs	Yes
CT Coalition	Demand Curve	Month	Yes, in a few years	Same time as new capacity	About 25% of ISO-NE	No
Pay as bid	Capped bid auction	1-year	Yes	No	$0.5 billion (in PJM)	Yes
Auction segments	Capped bid auction with bid floors	4-years, then yearly	Yes	Not for many years	$2.6 billion (in PJM)	Yes
Reliability Option	Descending clock auction	3 years	Probably, after many years	Probably	Unable to estimate	Yes

* Refers to total costs at EBCC for demand curves; high bid or segment at EBCC for others; and no reductions for other market revenues. These are very rough estimates for comparison purposes only.

E. Findings

Considering all the demand curves and other options discussed above, we make the following findings:

1. Demand curve mechanisms impose substantial new costs in large part because they require new entry payments (on average) to all capacity resources regardless of the price requirements (forward costs) of specific resources. These new entry payments are particularly inappropriate for resources that have already recovered most or all of their capital costs through cost of service regulation or divestiture sales, i.e., existing generators would get a windfall. Requiring consumers to pay twice for the same resource is difficult to justify, and may be illegal, under the Federal Power Act.

2. Demand curve mechanisms, while setting prices at the cost of new entry, may not attract sufficient numbers of new entrants due to the uncertainty created by annual one-year auctions. ISO-NE's proposal further compounds this uncertainty by establishing an "after the month" determination of what units qualify for the new entry payments. It is hard to see how a demand curve "revenue stream" with its substantial uncertainty will produce a financial projection that can attract new investment or secure a bank loan.

3. Demand curve mechanisms may not result in lower overall costs to consumers when constraints between zones are reduced (or eliminated) and lower-cost resources are providing more of the total resources needed. The reason is due largely to the slope of the demand curves and the fact that when the constraint is removed, consumers in the constrained zone see lower prices and costs and the consumers in other zones will see proportionally higher prices and significantly greater costs.

4. All of the resource adequacy options, including the demand curve mechanisms, require subjective determinations about demand or supply through an administrative process. None of the mechanisms are actual markets in a traditional economic sense, wherein unconstrained supply offers create a supply curve that intersects with a demand curve formed by unconstrained demand bids. This is not an unanticipated conclusion, but it deserves prominent mention in light of the considerable rhetoric about "market-based mechanisms" that accompany all of these various options, and seems to permeate FERC's thinking on these matters, too. Electricity markets, for numerous legitimate and unavoidable reasons, are not normal economic markets, and this is particularly true for electricity capacity markets.

5. Long-term resource adequacy mechanisms need to provide reliable service at reasonable cost. It is wrong to suggest that "scarcity" concepts can apply to the fundamental economic and human dependence on electric service in the United States. The ISOs, as control area operators, know that reliable service is a requirement, not an option. It is unreasonable to think that a demand curve price signal of any quantity can be a substitute for actual resources needed to meet peak load and reserve requirements. When it comes to electricity services, society is not prepared to "do without." The real challenge is how to design a resource adequacy mechanism that maintains a continuous, adequate supply of electricity at a reasonable price. Solutions will require policy and political choices that use both administrative and market tools to craft acceptable mechanisms.

6. All the approaches described in Sections B and C have significant administrative elements and corresponding flaws. Demand curves require the use of numerous initial assumptions about appropriate reliability levels and price targets, and then require continuous monitoring and updating of those assumptions. Discriminatory pricing options (distinguishing new and old units, pay as bid auctions, and segmented auctions) all require significant data collection and controversy over how individual units are characterized.

7. Market power concerns, particularly in transmission-constrained zones or load pockets, appear to be largely unaddressed by the demand curve proposals unless there are must-offer requirements and bids are capped. The most optimistic approach is to ensure that new entrants are participating in the bidding process to set an upper limit on exercises of market power during times of scarcity. New entrants, however, will have little influence on opportunities to exercise market power when prices are below the cost of new entry during times of surplus. Other problems with the demand curve approach include the lumpiness of adding new capacity resources in 100 or 200 MW increments, particularly in load pockets where the demand may only be a few thousand megawatts in total. Opportunities and the incentive to exercise market power may be exacerbated by demand curve mechanisms, when a small shift in resources can have a dramatic impact on price levels. While demand curves intend to provide incentives for new entrants, they may provide even stronger incentives for existing resources to exercise market power and impose barriers to entry.

8. The old "integrated resource plan" mechanism has been largely abandoned and labeled "unfashionable," yet it may offer a practical and useful option. RMR contracts and "gap RFPs" may provide cost-effective interim solutions. We may also be able to borrow ideas from successful "forward markets" in both electricity and other commodities markets and adapt good portfolio management practices.

The current proposals by the ISOs for kinked, arbitrary, and piecemeal demand curve approaches are particularly unappealing and ineffective. They are unproven mechanisms that expose all market participants to significant risks and place an unacceptably large cost burden on customers. The solution to finding a mechanism that will ensure adequate capacity resources at a reasonable cost will have to be a combination of market and administrative mechanisms developed as part of a thorough debate with all regional stakeholders. The FERC's appropriate role may be one of ensuring that regional mechanisms are compatible with one another, rather than substituting its judgment on the appropriate mechanism for the judgment of those entities that will have to live with and support the result.

Finally, the ability of ISOs to develop resource adequacy mechanisms may be constrained by their structure and roles. ISOs have established reliability as their number one priority. As a consequence, market efficiency, consumer costs, and resource financial stability become secondary considerations. The ISOs frequently emphasize that the "I" stands for "independence" and that each ISO is the only entity in the wholesale marketplace that does not have a financial interest in the market outcomes. In that sense, the "I" also stands for "indifference;" ISOs are indifferent to market outcomes and impacts on market participants. As long as system reliability is ensured, the costs that consumers pay and the financial perils that resource providers face are of little consequence to an ISO. The task falls to other public policy institutions to ensure that there is a balanced approach to decisions about resource adequacy and societal costs. We look forward to an open debate about the process and the mechanisms that could be utilized.

Appendix A: Proxy Peaker Cost Estimates

The charts below compare the proxy peaker estimates developed by NY ISO, ISO-NE and PJM

Table 7. New Entry CT Revenue Requirements Comparison

Source of Information	PJM SOM	PJM Study		NYISO Levitan Study		John Reed Testimony		e-Acumen Study
Plant Location	**PJM**	**NJ**	**NJ**	**ROS**	**ROS**	**Maine**	**Maine**	**NE ISO**
CT Model	**7FA**	**7FA**	**LM6000**	**7FA**	**LM6000**	**7FA**	**LM6000**	**7FA**
Number of CTs	1	2	2	2	2	1	2	1
Net Capacity (MW)	171.1	350.4	97.4	336.5	96.0	170.0	93.0	198.5
Heat Rate (BTU/kWh) (HHV)	10,500	10,443	9,618	10,809	9,739	NA	NA	10,500
Capital Cost ($Million)	$63.07	$156.51	$79.60	$201.50	$93.20	$95.20	$89.30	$81.98
Capital Cost ($/kW)	$368.59	$446.66	$817.22	$598.81	$970.83	$560.00	$960.22	$413.00
Levelized Fixed Costs ($/MW-Year)	NA	$66,642	$125,705	NA	NA	NA	NA	NA
Levelized Fixed Costs ($/MW-Day)	NA	$182.58	$344.40	NA	NA	NA	NA	NA
First Year Fixed Costs ($/MW-Year)	$68,472	$56,959	$107,440	$87,000	$133,000	$87,220	$147,000	$73,810
First Year Fixed Costs ($/MW-Day)	$187.60	$156.05	$294.36	$238.36	$364.38	$238.96	$402.74	$202.22
Financial Criteria Used								
Project Evaluation (Years)	15	20	20	20	20	20	20	15
Percent Equity	50%	50%	50%	50%	50%	50%	50%	50%
Percent Debt	50%	50%	50%	50%	50%	50%	50%	50%
Target IRR on Equity (%)	15%	12%	12%	12.5%	12.5%	12%	12%	14.13%
Loan Term (Years)	15	20	20	20	20	20	20	15
Loan Interest Rate (%)	8.78%	7.00%	7.00%	7.50%	7.50%	7.00%	7.00%	8.78%
MACRS Depreciation Schedule (Yrs)	15	15	15	15	15	15	15	15

From PJM RAM Stakeholder Working Group, Presentation 2, September 24, 2004.

Table 8. New Entry CT Revenue Requirements Comparison

New Entry CT Revenue Requirements Comparison

NEW ENTRY CT REVENUE REQUIREMENTS COMPARISON							
Source of Information	PJM Study		NYISO Levitan Study		ISONE Concentric		e-Acumen Study
Plant Location	NJ	NJ	ROS	ROS	Maine	Maine	NE ISO
CT Model	7FA	LM6000	7FA	LM6000	7FA	LM6000	7FA
Number of CTs	2	2	2	2	1	2	1
Net Capacity (MW)	350.4	97.4	336.5	96.0	170.0	93.0	198.5
Heat Rate (BTU/kWh) (HHV)	10,443	9,618	10,809	9,739	NA	NA	10,500
Capital Cost ($Million)	$156.51	$79.60	$201.50	$93.20	$95.20	$89.30	$81.98
Capital Cost ($/kW)	$446.66	$817.22	$598.81	$970.83	$560.00	$960.22	$413.00
Levelized Fixed Costs ($/MW-Year)	$66,642	$125,705	NA	NA	NA	NA	NA
Levelized Fixed Costs ($/MW-Day)	$182.58	$344.40	NA	NA	NA	NA	NA
First Year Fixed Costs ($/MW-Year)	$56,959	$107,440	$87,000	$133,000	$87,220	$147,000	$73,810
First Year Fixed Costs ($/MW-Day)	$156.05	$294.36	$238.36	$364.38	$238.96	$402.74	$202.22

Revised estimates from PJM RAM Stakeholder Working Group, Presentation 1, October 22, 2004.

Appendix B: MassAG/NSTAR Coalition alternative

A coalition of consumer advocates, large users, and a distribution utility filed joint testimony in the LICAP litigation.[47] The Coalition proposed a demand curve that is shown below in comparison to ISO-NE's curve

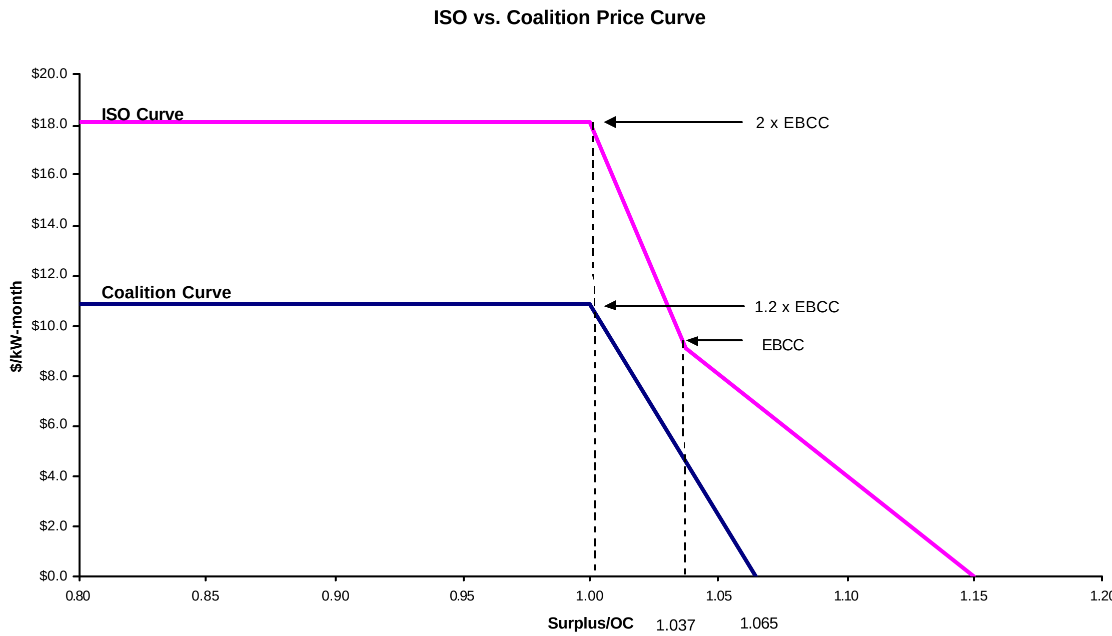

Figure 12. ISO vs. Coalition Price Curve

The key differences in the two curves are the Cmax and Cmin values. Both curves assume the same value for EBCC.

The Coalition sets Cmax at 1.065 as compared to ISO-NE's value of 1.15. The Coalition states that 1.065 represents a loss of load expectation (LOLE) of one day in 100 years, ten times greater than the historic planning standard of one day in 10 years. The ISO-NE value of 1.15 achieves an LOLE of approximately one day in 1250 years which the Coalition believes to be excessive and unnecessary.

The Coalition sets the price cap (Cmin) at 1.2 times EBCC as compared to ISO-NE's price cap of 2 times EBCC. The Coalition notes that ISO-NE's cap of 2 times EBCC will provide approximately a 30% return on investment, far in excess of any rate of return that has been authorized by either a state or federal regulatory agency.   The Coalition's cap of 1.2 times

[47] The coalition consists of the Attorney General of the Commonwealth of Massachusetts, the Attorney General of the State of Rhode Island, the Rhode Island Division of Public Utilities and Carriers, the New Hampshire Office of Consumer Advocate, NSTAR Electric and Gas Corporation, Associated Industries of Massachusetts, The Energy Consortium, and Strategic Energy LLC. The description of the Coalition's proposal is taken from the Direct Testimony of James Daly, Docket ER03-563-030, November 4, 2004.

EBCC will provide a return of 15-17% on new resource investment at a point where total New England capacity is at or below OC.

The Coalition curve with its Cmin and Cmax values creates a Ctarget at about 1.01 above Objective Capability (peak load plus reserves) as compared to ISO-NE's value of 1.054.[48] The Coalition states that ISO-NE's value of 1.054 is based on a recent 21 year average of actual excess capacity that has no bearing on what the target or goal should be in a competitive wholesale market.

In addition to an alternative demand curve, the Coalition's testimony advocates that only new resources should be eligible for demand curve revenues. Existing resources would continue to participate in the current ISO-NE installed capacity market. Many of those resources have already recovered substantial portions of their capital costs; all of them were built under the prior regulatory regime or the current (since 1999) competitive wholesale market regime. For resources that are needed for local reliability but are unable to recovery sufficient revenues, the Coalition proposes reliability-must-run (RMR) contracts. The Coalition notes that ISO-NE's demand curve proposal would create revenues for existing resources of approximately $10.4 billion dollars by 2010; this would be sufficient to purchase 17,000 MWs of proxy peaker units for a region that currently has a peak load and reserve requirement of about 28,000 MWs. The Coalition asserts that targeted RMR contracts are a much more cost-effective mechanism for compensating existing resources.

The MassAG/ NSTAR Coalition proposal with its alternative demand curve and limitations on payments to existing resources represents the least costly of all the alternative proposals in the New England LICAP litigation.

[48] As discussed in the body of this paper, ISO-NE's Ctarget level of 1.054 is achieved by putting a kink in the demand curve, Ck, at 1.037. This is the point at which capacity is paid the EBCC value. The steeper slope to the left of Ck will, over time, produce the Ctarget level of capacity according to ISO-NE's testimony.

Appendix C: CT Coalition alternative

Several CT state agencies filed an alternative proposal ion the LICAP litigation.[49] In addition to an alternative demand curve, discussed below, the CT coalition proposed an alternative mechanism for compensating capacity resources called a Reliability Option or RO (briefly discussed in Section C on alternatives).

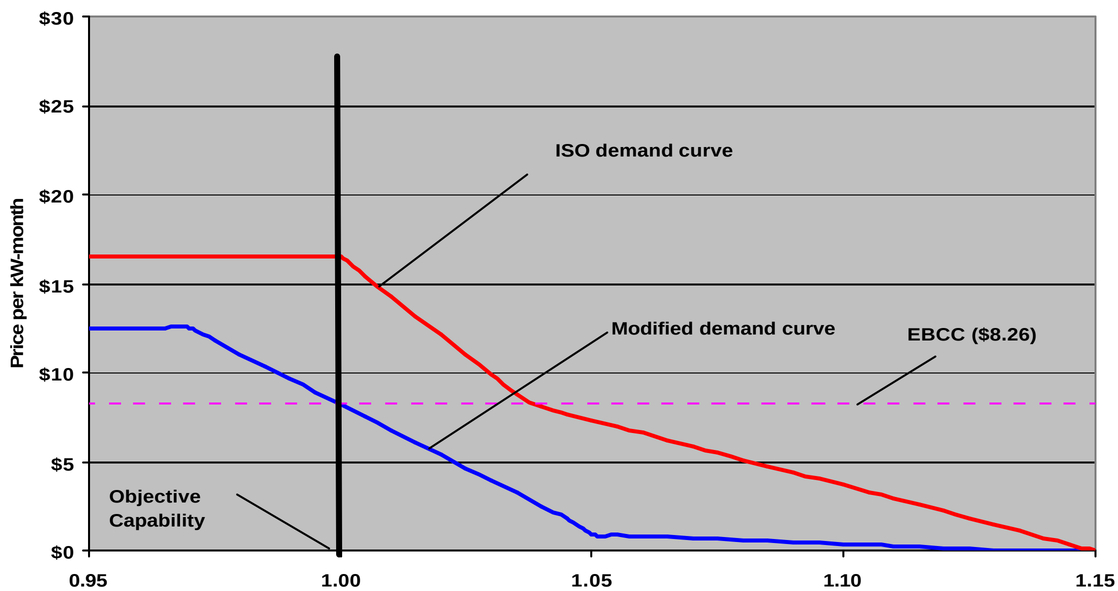

Figure 13. CT Coalition and ISO-NE Demand Curves

The key differences between the two curves are the values for Ctarget, Cmin, Cmax and addition of kinks (Ck). Both curves use the same value for EBCC.

CT Coalition sets Ctarget at 1.0 (OC or peak load plus reserves) as compared to ISO-NE's value of 1.054.[50] CT Coalition states that OC is the proper quantity (reliability) for a price equal to a proxy peaker resource (EBCC) based on a long term industry consensus that an LOLE of one day in 10 years is an appropriate standard.

The CT Coalition sets Cmax at 1.1375 as compared to ISO-NE's value of 1.15. CT Coalition states that 1.1375 represents an LOLE of one day in 900 years and that any additional capacity beyond that points has a no real value. CT Coalition also adds a kink at 1.048 (an LOLE of one day in 45 years) which results in a very minimal payment out to Cmax.

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[49] Connecticut Department of Public Utility Control, Connecticut Office of Consumer Council, Connecticut Attorney General, and Southwest Area Commerce and Industry Association of Connecticut ("CT Coalition").

[50] As discussed in the body of this paper, ISO-NE's Ctarget level of 1.054 is achieved by putting a kink in the demand curve, Ck, at 1.037. This is the point at which capacity is paid the EBCC value. The steeper slope to the left of Ck will, over time, produce the Ctarget level of capacity according to ISO-NE's testimony.

CT Coalition sets the price cap (Cmin) at 1.5 times EBCC as compared to ISO-NE's 2 times EBCC. Ct Coalition states that 1.5 times EBCC represents a proxy peaker resource with high risk and 100% equity funding earning a 12% return. CT Coalition notes that ISO-NE's value of 2 times EBCC will produce a 30-36% return on investment based on ISO-NE's testimony.

The CT Coalition estimates that using ISO-NE 2006 estimates that its demand curve will lower Connecticut's payments from $375 million (ISO-NE demand curve) to $41 million annually. New England's gross costs would be reduced from $953 million to $86 million.

Assuming greater scarcity, ISO-NE's demand curve would produce New England costs of $3.3 billion and Connecticut costs of $1.1 billion. The CT Coalition demand curve would reduce those costs to $700 million for New England and $400 million for Connecticut.[51]

[51] *See*, ER03-563-030, Pechman testimony at 70-71, November 4, 2004.

Appendix D: Segmented Auction

The basic idea behind a segmented auction is that resource needs are met in a sequence of stages, each stage representing a specified share of the total requirement. Each stage represents a separate auction with a single clearing price. Some basic requirements for this to work are that (1) the bids are capped close to cost and (2) existing resources can not bid in a later auction if they do not bid in the earlier ones. Each segment in sequence will clear at progressively higher prices, and the last segment will generally clear at the cost of new entry. The overall savings from a segmented auction compared to a single price auction depend on the nature of the supply curve, but are likely for the near to intermediate terms to be quite substantial.

<u>Initial structure</u>

Assume all bids are cost-capped by unit type (cost, or cost + 5%, or cost + 10%, etc.)

X= 25% of annual capacity target (OC, or OC plus 5%, or OC plus 10%, etc.)

a= lowest priced 25% of bids, cleared at a single price.

b= 2nd lowest priced 25% of bids, cleared at a single price.

c= 3rd lowest priced 25% of bids, cleared at a single price

d= highest priced 25% of bids, cleared at a single price (assumed = proxy peaker price)

Table 9. Segmented Auction with Capped Bids

Delivery Years . . .															
2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2005	Xa	Xa	Xa	Xa	Xa	Xa	Xa								
	Xb	Xb	Xb												
	Xc	Xc													
	Xd														
	2006	Xd	Xc	Xb	Xb	Xb	Xb	Xa							
		2007	Xd	Xc	Xc	Xc	Xc	Xb	Xa						
			2008	Xd	Xd	Xd	Xd	Xc	Xb	Xa					
				2009				Xd	Xc	Xb	Xa				
					2010				Xd	Xc	Xb	Xa			
						2011				Xd	Xc	Xb	Xa		
							2012				Xd	Xc	Xb	Xa	
								2013				Xd	Xc	Xb	Xa

Note that there are Xa, Xb, Xc & Xd auctions in every calendar year for different future delivery years. That should provide some continuity and stability for each of those markets and thus stabilize expectations of price values.

Let's consider how this would work with the PJM Supply Curve discussed previously in this paper. The first Xa auction for about 42,000 MW would clear close to 0. The next tranche Xb would clear at about 5 $/MW-day. The third tranche Xc would be about $10. And the fourth Xd would be at 65 $/MW-day. This would give a total annual resource cost of approximate $1,200 million, which is about three times greater than the minimal supply cost, but also less than a third of the single market cost.

Appendix E: ISO-NE zonal capacity clearing prices

In the chart below, we show the capacity clearing prices for the various zones within New England based on both the March and August ISO-NE proposals[52]. Note that capacity prices vary with level of capacity surplus. The March proposal is more expensive in the short term because the March curve provides much higher payments at surplus levels around 12%.

Table 10. Capacity Clearing Prices for the Various Zones within New England

.ICAP Clearing Prices and Annual Costs of Various

Current Proposals for 2005-06 Power Year

			LICAP Clearing Price ($/kW-mo)	
	Approx Capacity (units)	Surplus Level	Aug-04	Mar-04
SWCT	3,457	7.0%	5.45	6.31
Connecticut	3,908	10.5%	3.07	4.30
NEMA/Boston	5,903	11.5%	2.38	3.73
Rest of Pool	15,069	12.0%	2.04	3.44
Maine	2,517	12.5%	1.70	3.16
NewEng Total	30,854	11.2%	2.59	3.91

The table below shows ISO-NE's estimate of total costs of its August proposal for next year (2005). It includes estimates of current ICAP payments, RMR contracts, and excess energy revenues that would be reductions to total system costs

[52] ER03-563-030, LaPlante testimony, August 31, 2004. Based on LaPlante testimony, but calculations by Synapse.

Table 11. Illustrative LICAP Costs for ISO-New England by Zone

Annual Cost Impact of ISO Proposal for 2005-06 Power Year[53]

($ in millions)

	ICAP Price $/kW-mo	Annual LICAP Payment ($ in millions)	RMR Offset ($ in millions)	Capacity Market Offset ($ in millions)	Energy Revenue and Availability Offset ($ in millions)	Net Impact ($ in millions)
SWCT	5.40	$224	$41	$30	$48	$106
Rest of Connecticut	3.22	$151	$94	$28	$39	($10)
NEMA/Boston	2.40	$170	$37	$42	$54	$36
Rest of Pool	1.93	$349		$96	$122	$131
Maine	1.92	$58		$16	$20	$21
NewEng Total		$952	$172	$212	$283	$284

The offsets represent current payments that either would be eliminated (RMR and Capacity Market) or that would reduce (Energy Revenue and Availability) the ICAP payments.

Below is a table of estimated costs contained in testimony in the FERC litigation. It is based on the same type of analysis that ISO-NE used to create its estimates for the 2005-2006 power year, but it extends those estimates out through the 2009 power year.[54]

Table 12. Net Incremental Cost Impact by Zone ($Millions)

	NEMA	ROP	Maine	ROCT	SWCT	TOTAL
2006	$140	$407	$68	$22	$85	$722
2007	$257	$677	$112	$100	$168	$1,314
2008	$373	$941	$156	$176	$250	$1,896
2009	$489	$1,208	$201	$252	$333	$2,483
2010	$799	$1,923	$319	$457	$552	$4,050

53 ER03-563-030, LaPlante testimony at 21, August 31, 2004. This table is taken from LaPlante's testimony with the addition of totals.

54 This table is taken from the Mass AG/NSTAR's filing on behalf of a coalition of New England entities. The analysis was based on the same model (GE Multi Area Reliability Simulation or GE "MARS) used by ISO-NE. *See*, ER03-563-030, Daly testimony, p.13-14, November 4, 2004.

Table 13. Clearing Price by Zone in Dollars per kW-month

	NEMA	ROP	Maine	Rest of CT	SWCT
2006	$3.64	$3.64	$3.64	$3.64	$3.64
2007	$5.32	$5.32	$5.32	$5.32	$5.32
2008	$6.96	$6.96	$6.96	$6.96	$6.96
2009	$8.62	$8.62	$8.62	$8.62	$8.62
2010	$13.02	$13.02	$13.02	$13.02	$13.02

Appendix F: Summary Comparison of Three ISO Resource Adequacy Proposals

The table below summarizes the three ISOs' proposals with regard to future electric installed capacity. Major differences are highlighted in gray.

Table 14. Summary Comparison of Three ISO Resource Adequacy Proposals

	NY ISO	ISO NE	PJM
Basic Mechanism	A "demand curve" auction for resources administered by the ISO.	A "demand curve" for auction resources administered by the ISO.	A "demand curve" with multiple products administered by the ISO.
Proposal Vintage	Implemented May 2003	Proposed August 2004	Proposed September 2004
Loss of Load Relationship	Target level roughly based on 1 day in 10 year LOLE.	Objective Capacity (OC) level is determined by 1 day in 10 year LOLE.	Target is 1 day in 10 years LOLE.
Target Resource Level	A UCAP level of 12% above peak load with zonal adjustments.	Based on historic reserve level (3.7%) above OC.	Resource Level that meets Loss of Load criteria at about 15% reserve level.
Target Price Level	New capacity cost in the zone.	New capacity cost in the zone minus ex-post inframarginal CT revenue.	New capacity in the zone minus ex-ante inframarginal CT revenue.
Price Curve	Straight - About twice target price at peak load level (12% below target). Goes to zero at same distance above target level.	Kinked - Price is capped at twice target price at OC level. Goes to zero at 15% above OC	S-shaped: Steep about target reserve level, more gently sloped at higher and lower reserve levels. Approaches zero at about 30% reserve level.
Resource Price	Mkt Clearing Price	Mkt Clearing Price	Mkt Clearing Price
Time Horizon	Six months.	Monthly	Four years in advance.
New Resource Incentives	Deficiency auction prices will induce long term bilateral contracts	Anticipation of monthly payments.	One year contract four years in the future.
Existing Resource Payments	Monthly based on auction.	Monthly payments based on availability.	Based on availability.
Program Costs	Only the capacity in the deficiency auction in a zone receives the clearing price. Current levels ~$300 million/year.	All capacity receives the same price which is expected on the average to be the cost of a new resource. Total cost could be ~$2 billion/year.	All capacity in the future likely to average at the price for new entry. Total cost could be ~$8 billion/year.
Demand Resources	Demonstrated increase in contracts for demand resources	Potentially.	Yes.
Transmission System Upgrades.	Not part of mechanism	Not part of mechanism	Upgrades included in four-year advance model
Intermittent	Uncertain	Uncertain	Uncertain.

Resources			
Local Resource Incentives	Locational prices encourage new local resources.	Locational prices encourage new local resources or additional transmission.	Locational prices encourage local solutions.

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ER03-647-000, Order Approving NYISO Demand Curve Filing, May 20, 2003.

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ER03-647-004, Order Accepting NY ISO Report on Demand Curve, September 22, 2004.

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