ICAP Reform Proposals
In New England and PJM

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INTRODUCTION

Each of the eastern Independent System Operators (ISOs) has been developing reforms to the installed capacity (ICAP) mechanisms they use to achieve resource adequacy. Following the development by the New York Public Service Commission and the New York ISO (NYISO) of locational capacity markets and the introduction of a downward sloping demand curve for defining capacity payments, the ISOs in New England (ISO-NE) and PJM are proposing to introduce similar concepts in their regions. The ISO-NE and PJM proposals borrow from and refine the two NYISO approaches, while proposing additional features to address some of the issues believed to be limiting the effectiveness of their existing ICAP markets.

This paper examines the ICAP market reform efforts underway in New England and PJM. It first summarizes the conditions, issues and FERC decisions that led to the ISO-New England "LICAP" proposal, which is now before FERC, and to PJM's Reliability Pricing Mechanism (RPM) proposal, which has been under development for over a year and was filed at FERC on August 31, 2005. The paper then examines these two proposals in some detail, focusing on how each proposal attempts to address each of the problems these ISOs are having with their current ICAP markets.

The reform proposals share key features. Both ISOs propose to move from a regionally uniform approach to capacity requirements and prices to locationally different requirements, markets and prices that recognize the transmission constraints that limit the deliverability of capacity from one region to another. And both ISOs would use a downward sloping demand curve to determine capacity prices consistent with the investment requirements for meeting their resource adequacy goals. But the two ISOs approach their respective reforms from two very different perspectives, with New England relying somewhat more on market driven responses to short-run prices and PJM relying more on an integrating planning and long-run acquisition approach overseen by the ISO. The differences are not always sharp; both ISOs use administrative means to establish their respective resource adequacy goals and both administratively define the demand curves that determine the prices to be paid for capacity bought and sold through ISO-administered auctions. Both rely on their respective transmission planning processes to help guide resource adequacy decisions. But here the two approaches separate in ways that illustrate some basic policy choices.

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[1] This paper was prepared at the request of the California Independent System Operator to assist the California ISO in its consideration of alternative mechanisms to assure resource adequacy. The paper has benefited from comments from Scott M. Harvey, William W. Hogan, Mike Cadwalader, and Dmitri Perekhodstev, with research assistance from Alexis Maharam, all of LECG, as well as helpful comments from James Bushnell and the California ISO Staff. The views expressed here are solely those of the author, and any errors are solely the author's responsibility.

The ISO-NE approach focuses on defining the right set of price incentives that will not only support the target level of capacity investment but also allow the market to decide the types and features of capacity resources that the market will build and retain. While the ISO-NE would administer short-run markets to set these prices each month, the philosophical approach is to leave the choice about which investments and operational features to choose largely to the market. The New England approach also tries to focus payments for "capacity" to those who actually provide reliability in real time, rather than simply to any generator that has installed "capacity." At present, the definition does not include demand alternatives, although in theory it could. Locationally different capacity prices are then viewed as a common incentive framework from which the market, more than the integrated planner, can consider alternative investments in generation versus transmission upgrades. In the New England approach, transmission planning would still be performed by the ISO, and identified transmission needs would be affected by the generation market's response to locational capacity prices and hence to local reliability needs, but transmission investment is not otherwise explicitly linked to the generation resource adequacy framework.

In contrast, the PJM approach not only defines the prices to support investments but also has the ISO itself involved in deciding which operational features to reward. The ISO-selected features – such as load following or 30-minute quick-start capability -- are directly rewarded through higher payments; features not selected may not be rewarded at all or rewarded only indirectly. In addition, the PJM approach adopts the integrated planning paradigm by linking a long-run planning approach for transmission expansion with a long-run procurement approach for all infrastructure. The intent is to allow alternative investments in generation and transmission, as well as demand-side response, to compete in the same ISO-administered auction. Moreover, whereas the New England approach apparently accepts the view that short-run capacity auctions and prices can provide a sufficient basis for long-run investment decisions (in conjunction with bilateral contracts and self supply decisions designed to hedge short-run price risks), PJM asserts that short-run prices alone will not provide sufficient encouragement or support for long-run investments.[2] The PJM proposal thus features a series of forward auctions for products to be delivered as much as four years in the future, based on the apparent belief that without such forward obligations, the appropriate investments would not be made.

The reform efforts in PJM and ISO-NE both contrast with a very different approach under consideration by the Midwest ISO. The Midwest ISO (MISO) currently has no explicit ICAP requirement or ICAP markets beyond the sub regional resource adequacy requirements that preceded the formation of the MISO.[3] Rather than further develop an ICAP requirement and offer ICAP markets similar to those in PJM, New York and New England, the Midwest ISO is

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[2] According to the PJM RPM filing, "Future reliability can best be assured through an integrated solution, which supplements transmission enhancement identified in the RTEP process with a system of long-term capacity price signals to encourage new capacity resources to locate in the areas of greatest need." PJM Reliability Pricing Model submitted to the Federal Energy Regulatory Commission (FERC) on August 31, 2005 (PJM Filing), at 45.

[3] The MISO Transmission and Energy Market Tariff does impose a minimum 12 percent planning reserve requirement on load-serving entities, but there are no detailed rules for implementing this requirement, nor are there provisions that would allow the MISO to administer capacity markets. *Midwest ISO Open Access Transmission and Market Tariff Module E - Resource Adequacy,* effective April 1, 2005.

exploring whether an "energy-only" market approach could be implemented in the MISO footprint in lieu of an explicit ICAP requirement. At this time, MISO has only issued a brief "white paper" outlining the concept, in the hope of stimulating further discussion among stakeholders.[4] To allow an informed comparison of this approach, a companion paper prepared for the California ISO by William Hogan examines the theory and concepts behind an energy-only approach for achieving resource adequacy.[5]

This report on ICAP reform efforts in New England and PJM should also be read in conjunction with a recent report prepared by Scott Harvey for the California ISO,[6] which describes and examines the existing mechanisms used by PJM, the New York ISO, and ISO-New England. As noted in the Harvey and Hogan papers, the existing ICAP mechanisms share a common conceptual framework: the notion that because of various caps on the spot market prices paid to generators for energy and ancillary services, adequate generation to meet each region's resource adequacy goals can be sustained only if generators receive a supplemental source of revenues through payments for a product called "capacity" that is different from "energy." Through these supplemental payments, generators are expected to recover the "missing money" caused by the imposition of price caps and other mechanisms that keep energy and operating reserve prices below competitive levels[7] – and hence below levels sufficient to sustain the desired level of investment. The reform proposals in PJM and ISO-NE are based on this same framework.

Common Issues Driving ICAP Reform Efforts in New England and PJM

The ICAP reform efforts in the Northeast appear to be driven by a set of common concerns with the current ICAP mechanisms. The concerns arise partly from the way that the ICAP markets function, but they also arise from how "capacity" is defined and hence what suppliers must do to receive payments for providing capacity. Indeed, the ISO-NE proposal seeks in part to redefine "capacity" as an obligation to provide energy or operating reserves during periods of operating

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[4] Midwest ISO, "Draft Discussion Paper on Resource Adequacy for the Midwest ISO Energy Markets," August 2005 (MISO White Paper).

[5] William Hogan, "On an 'Energy-Only' Electricity Market Design for Resource Adequacy," draft submitted to CAISO, September 2005.

[6] Scott M. Harvey, "ICAP Systems in the Northeast: Trends and Lessons," submitted to CAISO, September 2005. (ICAP Systems)

[7] As explained further in the Harvey and Hogan papers, energy and operating reserve prices in the ISO spot markets can be kept below competitive market-clearing levels by several factors. These include: (1) the imposition of a general "safety valve" offer cap, typically set at $1,000/MWh in eastern ISOs (currently $250/MWh in California); (2) the absence of any explicit shortage-cost pricing mechanisms to allow prices to reflect the value of lost load (VOLL) during shortage conditions; (3) the imposition of unit specific offer caps when an offer fails the "conduct and impact" tests, or in situations involving transmission constraints and the need for redispatch, such as the PJM rule to cap offer prices at cost plus 10 percent when a unit must be dispatched out of merit as part of congestion redispatch or cost plus 40 percent for frequently mitigated units; (4) dispatch, commitment and pricing rules that allow an ISO to hold high cost units at minimum generation (such as for contingency purposes) but thereby prevent these high cost units from setting the market-clearing prices at their locations; and (5) inconsistent pricing between energy and operating reserve markets that fail to reflect shortage values when operating reserves fall below desired levels; and so on.

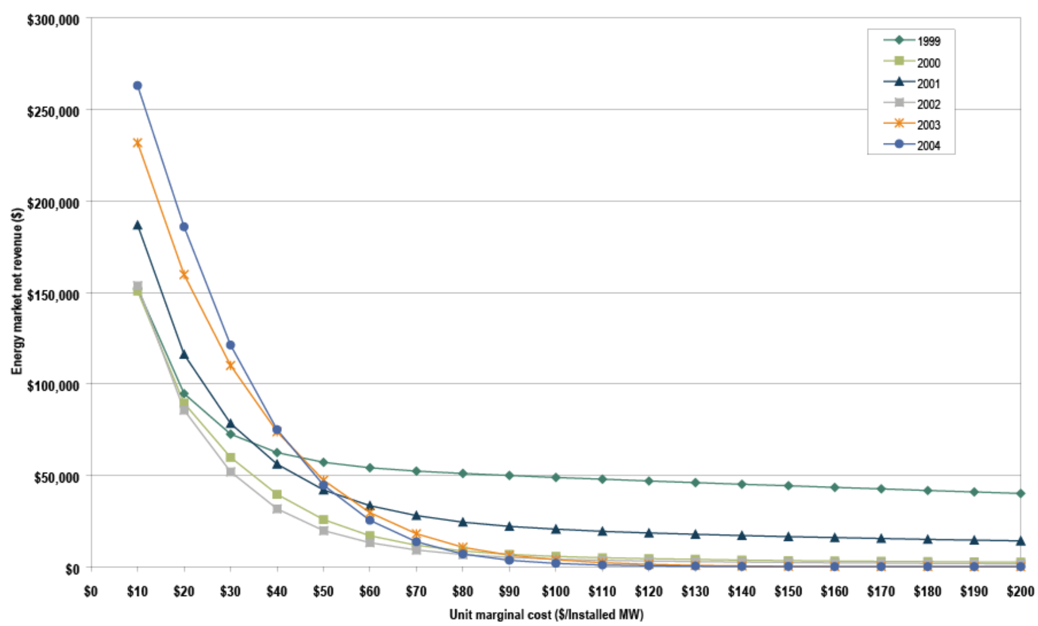
reserve shortages, and the designers use an "energy-only" model as a principal source for guidance in redesigning New England's ICAP mechanism.

Each ISO has a separate history about how their reform efforts came about; key elements of each history are summarized in this section, while a chronology of related FERC filings and Orders appears in two Appendices. But all of the eastern ISOs share several common and closely related concerns with their ICAP mechanisms:

1. Insufficient market revenues to support needed investment in key areas.

Both New England and the original footprint of PJM experienced generation construction booms a few years back, resulting in region-wide surpluses of capacity relative to each of the ISOs' resource adequacy criteria. The regional surplus, as well as offer price mitigation schemes intended to mitigate market power in transmission constrained areas, combined to depress market prices for energy and operating reserves, pushing generation margins – and hence contributions to fixed costs – to near zero for peaking units. The trend of declining margins in PJM is shown in Figure 1.[8]

Figure 1
PJM Energy Market Net Revenue
By Unit Marginal Cost

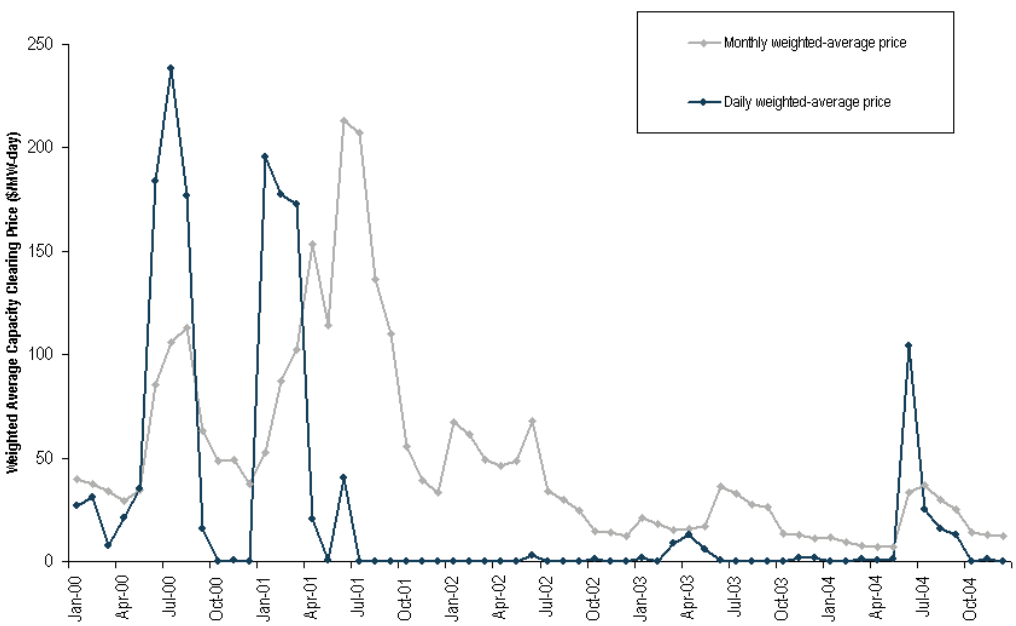


Source: PJM

[8] PJM figures are reprinted with permission from a PJM presentation by Andy Ott, "Current Installed Capacity Markets: How Well Have They Worked?" April 11, 2005. These figures also appear in the PJM RPM filing, submitted to FERC on August 31, 2005.

The capacity surplus also caused capacity market prices to fall since 2001 to near zero levels, an effect driven as much by the use of a vertical demand curve (discussed below) as by the capacity surplus. In PJM, this trend was briefly interrupted in 2004, but only because of what PJM found to be capacity shortages caused when a large generation owner physically withheld capacity from PJM's capacity credit markets. The trend in capacity prices in the PJM region is shown in Figure 2.

Figure 2
Prices in PJM Daily and Monthly Capacity Markets



Source: PJM

The combined effect of depressed energy prices and depressed capacity prices has left most generators with insufficient revenues to cover fixed operating costs and investment costs. The problem extends not only to peaking units but also to intermediate and base load units. For example, PJM has estimated that over the last five years, combustion turbines would have earned from margins in the PJM energy markets only about half of the revenues needed to recover fixed costs, while intermediate and base load units would have recovered about two thirds or less of the revenues needed to cover their fixed costs.[9] With capacity prices tending towards zero under

[9] PJM, presentation by Andy Ott, "Current Installed Capacity Markets: How Well Have They Worked?…" April 11, 2005, at 6. The figures appear to compare the annual fixed cost (on a 20-year levelized basis) versus an estimate of the average annual net revenue from PJM markets between 1999 and 2004, suggesting there is little existing incentive for new entry. For similar findings, see Federal Energy Regulatory Commission, *State of the Market Report*, Washington D.C., June 2005, at 60.

the current ICAP designs, generators would likely not have recovered their remaining fixed costs from the sale of capacity.[10]

The result of these trends has been a substantial fall off in proposals for new capacity – only about 111 MW were added in 2003-2004 with another 920 MW under construction. There is almost no new capacity proposed for the region. At the same time, there has been a substantial increase in the number of retirements. In PJM, 1,973 MW of capacity were retired in 2003 to 2004, and owners have proposed an additional 2,400 MW for retirement for the 2005-2007 period, most of this in Eastern PJM (primarily New Jersey). In the meantime, load growth in Eastern PJM was expected to increase capacity requirements by about 2,500 MW. Without significant capacity additions and/or transmission upgrades into the area, Eastern PJM would be unable to meet reliability requirements as early as 2008.[11]

The natural result of these trends in both PJM and similar trends in New England would be an expected decline in the level of capacity surplus, which on its own would not be a cause for concern. However, in both regions, the substantial increase in retirements and the absence of significant new investments have been occurring primarily in local areas of each region that tend to be transmission constrained – that is, in areas where there is a limited ability to move power from surplus capacity from the broader region to areas with high loads and little if any surplus, such as New Jersey in PJM and Boston or Southwest Connecticut in New England. In short, market prices for both energy and capacity were failing to signal and support the investment needed to maintain existing plants or construct new plants in locations with a growing need for capacity.

2. Absence of locational requirements and locational price signals.

All of the eastern ISOs operate bid-based dispatches and corresponding spot markets for energy (and in some cases, operating reserves), in which settlement prices for energy are based on defining the locational marginal price (LMP) at each location. In the case of generators, settlements for imbalances and spot purchases and sales are on a nodal basis – that is, there is a distinct LMP for each generator's bus. However, offer caps and other limits on how high the LMPs can rise during shortage or transmission constrained conditions can prevent the LMPs from reaching competitive market-clearing levels if the caps do more than merely limit the exercise of market power. Logically, this would suggest that if a payment for "capacity" is made to generators to make up for the "missing money" caused by the energy price limits, then these capacity payments might also need to be differentiated at the nodal level. However, although there were locational ICAP requirements in New York, the ICAP requirements and markets in New England and PJM applied a uniform ICAP requirement for the entire footprint of each ISO.

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[10] According to PJM's Market Monitor, " . . .net revenue in the PJM Region has been below the level required to cover the full costs of new generation investment for several years and below that level on average for new peaking units for the entire market period." PJM RPM Filing, Bowring Affidavit, at 15.

[11] PJM, "Immediate Reliability Issues in the Absence of RPM," Attachment B to Letter from Phil Harris to the PJM Members Committee, page 2, posted to the PJM website for the PJM Annual Meeting, April 19, 2005. Also see, PJM RPM Filing, Affidavit of Steve Herling, at 7-8.

This meant each ISO conducted ICAP auctions on an ISO-region-wide basis, deriving a single, uniform clearing price for all capacity in the region, regardless of the capacity's location.

As seen in New York, transmission limitations on the deliverability of capacity between sub-regions of the NY ISO footprint, especially into New York City and Long Island, created locationally different market prices and values for capacity. These considerations convinced the New York Public Service Commission and the member systems of the New York Power Pool to include separate capacity requirements for New York City and Long Island, compared to the rest of New York, in the original NYISO market design, and to limit the extent to which these sub-regional requirements could be met by reliance on capacity located in the "rest of state" ("ROS") zone.[12] This approach allowed monthly prices for capacity to differ between the three sub-regions, but not within each sub-region.

The same considerations affected PJM and New England. Without any location price differences for capacity, the uniform prices paid to generators failed to encourage appropriate generation investment in locations where capacity would be more valuable and contribute more to local reliability. Conversely, the absence of locational price signals failed to discourage investments at locations where capacity was less valuable, including locations where additional capacity would add little if anything to regional reliability. In New England, for example, areas in Maine with lower costs had become attractive locations for new capacity investments, but transmission constraints limited the ability to move that power both out of Maine and into load centers further south – such as Northeast Massachusetts (NEMA) and Boston, as well as Southwest Connecticut. The regionally uniform capacity payment approach tended to encourage further capacity investments in Maine but too little investment in NEMA-Boston or SW Connecticut.

Similarly, in the first years of the PJM markets, the PJM region experienced a boom in new plant construction, allowing the region as a whole to achieve capacity levels above the industry standard of 1-day in 10-years Loss of Load Expectation (LOLE). But at the sub-regional level, this adequacy began to change in 2003-2004, following the announced retirement of several older plants in New Jersey, at the eastern end of PJM.[13]

Until the announced retirements, all capacity in PJM could be deemed "deliverable" to loads by counting the simultaneous contribution from both western and eastern generation.[14] But the announced retirement of significant capacity generation in New Jersey undermined the basis for this claim, exposing a weakness in the "deliverability" concept upon which PJM had been relying. At this point, PJM concluded that, like New York and New England, it too would need

[12] The capacity requirements that must be met by local generation (and not imports) are set by the New York State Reliability Council.

[13] See, Appendices A and B for summaries of ISO filings and FERC Orders related to retirements, the expansion of RMR contracts and the need to redesign each ISO's ICAP markets.

[14] For a further discussion of the PJM concept of "deliverability" and the difficulties it ran into when the retirements were announced, see pages 20 to 28 in "ICAP Systems in the Northeast: Trends and Lessons."

to have locational requirements and locationally different prices to provide better incentives for ICAP investments in areas affected by transmission "deliverability" constraints.[15]

3. An increase in the number of Reliability-Must-Run (RMR) Contracts

One of the consequences from the absence of locational price signals for capacity is that ISO-NE and PJM began to experience an increase in the number of plants applying for RMR treatment as a way to cover their fixed costs. RMR contracts are typically used with older plants in transmission constrained load pockets where the ISO concludes that specific units are needed for reliability purposes, but revenues from the offer-capped energy markets are not sufficient to cover these plants' fixed costs. To avoid premature retirement of these units, the ISOs contract with the needed plants to remain available, with the contracts typically covering going forward fixed costs that would not be recovered because of limits on energy and/or operating reserve prices.

In New England, RMR contracts had been used for several years, but this problem became more apparent in early 2003 when several independently owned units located in Southwest Connecticut filed with FERC for approval of RMR contracts with the ISO.[16] The Southwest Connecticut region had a history of underinvestment in transmission and generation, with serious limits on the ability of generation outside the local area to meet reliability requirements within the local area.[17] However, in ruling to limit the *Devon* RMR requests, the FERC criticized ISO reliance on RMR contracts on several grounds and directed the ISO to begin developing an alternative, market-based approach that would reduce (if not eliminate) reliance on RMR contracts.[18]

The FERC's criticisms of RMR contracts in the April 25, 2003 Order provide an initial view of what FERC expected from ISO-NE, and presumably other ISOs, with regard to compensating units needed for local reliability. In particular, the Commission expressed concern that the effect of RMR contracts was to remove high cost units from the calculation of the

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[15] PJM RPM Filing, at 5-6.

[16] There were two sets of these filings:

(1) PPL Wallingford's cost of service agreement with ISO New England:
Cost of Service Agreement Among PPL Wallingford Energy LLC, PPL EnergyPlus, LLC and ISO New England, Inc in FERC Docket ER03-421-000 (January 16, 2003 Filing)

(2) Devon Power LLC, et al's cost of service agreement with ISO New England, which became the lead docket in the development of the ISO-NE LICAP proposal:
Reliability Agreements Among Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, NRG Power Marketing Inc., and ISO New England Inc. in FERC Docket ER03-563-000 (February 26, 2003 Filing)

[17] Like other ISOs, ISO-NE had specific provisions authorizing the use of RMR contracts in such cases, and these provisions had been approved by FERC when it approved ISO-NE's "Standard Market Design" tariff. *Order Accepting in Part and Modifying in Part Standard Market Design Filing and Dismissing Compliance Filing* 100 FERC ¶ 61,287 (September 20, 2002 Order)

[18] *Order Accepting, in Part, Requests for Reliability Must Run Contracts and Directing Temporary Bidding Rules* 103 FERC ¶ 61,082 (April 25, 2003 Order)

market-clearing prices (LMPs) at each location. Units under RMR contracts might be scheduled by the ISO or committed for local reliability purposes. The units could be held at minimum generation levels and kept available in case of some local contingency, so these high cost units would not set the LMPs, and their incremental energy costs would not set prices within the potentially constrained region. LMPs set at the unconstrained level would exacerbate the "missing money" problem for any other plant selling power within the potentially constrained region but not subject to an RMR contract. The result could in turn lead units that were not currently under RMR contracts to seek cost recovery through RMR or similar contracts, thus systematically undermining the market for a growing percentage of plants.[19] The need for a market-based alternative to the growing reliance on RMR contracts was thus driven in part by a concern that the entire market structure might ultimately be at risk.

In its April 25, 2003 Order limiting the *Devon* RMR contracts, FERC directed ISO-NE to develop a market-based alternative to the growth in RMR contracts. FERC suggested either a locational ICAP approach (as New York had implemented for New York City and Long Island) providing increased compensation to generators located in transmission constrained areas, or some other market-based "deliverability" mechanism that would ensure that capacity developed in other areas would be deliverable to such local areas and be appropriately compensated. FERC did not specify what a "deliverability" option might look like, and a locational ICAP approach had already been implemented (and approved by FERC) in New York and proposed by PJM for its region. In response to the order, ISO-NE therefore chose to develop a locational ICAP (LICAP) approach for New England.

The same issue regarding RMR contracts arose in PJM. There, the announced retirement of several generating units in New Jersey created a concern because some of these units have been relied on for local reliability purposes. PJM did not initially have a formal policy for handling announced retirements, and at FERC's urging, PJM developed rules that would allow PJM to defer a retirement for a limited period and provide compensation to that unit that covers the unit's going forward costs needed to keep the unit operational. In approving this approach, however, FERC made clear that an ISO could not indefinitely prevent a unit from retiring. In addition to providing RMR or other short-run compensation schemes, FERC indicated that an ISO must provide market-based mechanisms that would, as much as possible, address the long-run "reliability compensation issue."[20]

[19] Rebuttal Testimony of Dave LaPlante, submitted in the ISO-NE LICAP case, Docket ER03-563-030 (LaPlante Rebuttal) at 4-5, 49. The number and range of RMR contract applications has increased substantially during the two years in which ISO has been developing and seeking approval of its LICAP mechanism. New RMR requests have been submitted for nearly 4600 MW, in some cases by newer, more efficient combined cycle plants, not merely older peaking units. LaPlante Rebuttal 4-5. There are currently about 2200 MW of capacity under existing contracts. See also, *California Public Utilities Commission Capacity Markets White Paper*. August 25, 2005 p. 37 (California White Paper)

[20] See, FERC, Order on Tariff Filing, 107 FERC 61,112, May 6, 2004, (May 6, 2004 Order). Filings and Orders leading up to this Order are summarized in Appendix A.

4. Ineffectiveness of "Safe Harbor" Bids in Recovering Fixed Costs

In the ISO-NE LMP-based market rules that FERC approved in its December 20, 2002 Order,[21] the ISO established a mechanism intended to allow seldom used generators in transmission constrained areas to submit bids high enough to recover both fixed and operating costs, provided these plants were actually dispatched, and their bids actually set the market-clearing LMPs often enough. This mechanism, called the "CT Proxy," allowed generators in transmission constrained areas to increase their energy offers above levels that would otherwise be subject to market power mitigation to give them an opportunity to recover their fixed costs in energy prices.

In its April 25, 2003 Order in the *Devon* case, FERC directed ISO-NE to replace the CT Proxy mechanism and substitute a conceptually similar approach that would allow seldom run (10 percent capacity factor or less) peaking units in locally constrained areas to submit "safe harbor" bids. Peaking Unit Safe Harbor (PUSH) bids would be defined by the amount of revenues a seldom dispatched peaking unit would need to recover from the ISO's energy market if its bids set the clearing price and if the peaking unit were dispatched the same number of hours as in the preceding year. Bids at or below the PUSH levels would not otherwise be subject to the ISO's offer mitigation rules. As with the CT Proxy approach, FERC apparently hoped that by creating a safe harbor for higher energy price offers, the PUSH bidding mechanism would raise LMPs in constrained areas high enough to replace the "missing money" and thus eliminate or greatly reduce the need for RMR contracts. FERC directed ISO-NE to use the PUSH bidding mechanism on an interim basis -- until ISO-NE implemented a locational ICAP or other deliverability mechanism.[22]

The PUSH mechanism never worked as advertised and so did not reduce the need for RMR contracts. In a December 4, 2003 report back to FERC on its experience with PUSH, the ISO-NE noted that the mechanism had so far failed to allow the affected generators to recover their fixed costs and failed to eliminate the need for RMR contracts for the affected units.[23] ISO-NE cited several reasons for this apparent failure, but three related reasons seem particularly relevant:

(1) The permissible level of a PUSH bid for each unit is determined by the number of hours that unit was dispatched in the prior year, but there was no reason to expect the prior year's dispatch would be a useful indicator of this year's dispatch. A significantly lower level of dispatch in the current year compared to the prior year could result in failure to cover a given unit's fixed costs, even if the higher PUSH bids set the LMPs. While this might average out over several years, the variability from year to year could

[21] ISO-NE implemented the new market rules on March 1, 2003.

[22] Generators in PJM also proposed "safe harbor" bidding mechanism for that region. See, Reliant, *Request for Approval of a Formula Proxy CT Methodology for Certain Reliant Energy Mid-Atlantic Power Holdings, LLC Generating Facilities in PJM Interconnect*, FERC Docket EL03-116-000. Although FERC rejected this request, the issue sparked a FERC reevaluation of reliability compensations issues for the PJM region. See Appendix A.

[23] ISO-NE, *Review of PUSH Implementation and Results* in FERC Docket ER03-563-025. December 4, 2003. (December 4, 2003 Report)

expose each unit to substantial risks, but without matching the change in compensation to the incentives needed during stressed hours in real time.

(2) Although the ISO often committed PUSH eligible units for local reliability reasons, they were not dispatched in enough hours to achieve cost recovery. One reason was that the number of hours dispatched in a prior year was based on the units submitting lower offers (possibly mitigated); when the same units submitted higher PUSH bids, they were less often economic and so were dispatched less often.

(3) PUSH eligible units were often committed for local reliability reasons, and they were often held at minimum generation levels as 2nd contingency reserves. This meant the units would not be dispatched for energy except when the 2nd contingency occurred. Under the ISO's pricing rules, units operating at minimum generation are not on the margin and hence not eligible to set the market-clearing LMPs, even though their PUSH bids might be significantly higher than the units actually on the margin and setting the LMPs. At the same time, the 2002 New England market rules had eliminated market-based payments for reserves, including those held for 2nd contingency purposes.[24]

In sum, although PUSH eligible units did submit higher bids than in the past, their bids did not set the LMPs often enough to allow the units to recover their fixed costs.

The concept of a "safe harbor" implies that offer prices that would otherwise be subject to market power mitigation would be permitted to set market-clearing prices. That is, absent safe harbor status, the offer price would have been sufficiently above assumed operating costs of the unit that the offer prices would have been viewed under the market rules as efforts to exercise market power through economic withholding. There was considerable discomfort among state regulators and load-serving entities about any mechanism that permitted very high generation offers. Hence, the PUSH mechanism lacked support from both generators (because it didn't seem to be working) and loads (because they feared it might become a shield for market power).

The PUSH bidding mechanism is still in effect in ISO-NE. Under FERC's Order, the interim mechanism must stay in place until ISO-NE implements LICAP or some other mechanism to address the reliability compensations issues and the growth of RMR contracts. But there have been no further efforts to extend the use of the PUSH or similar concepts beyond the interim period.

5. Vulnerability of ICAP Markets to Market Power

Existing ICAP markets in the Northeast have been criticized for their vulnerability to the exercise of market power, such as through physical withholding in the monthly ICAP markets (or the effect on forward bilateral markets of the threat of such withholding in the ICAP spot market).[25] The motivation and opportunity for withholding stems from the fact that in the PJM

[24] PJM has since implemented a forward market for operating reserves.

[25] ICAP withholding not only raises capacity prices for remaining capacity but can also reward a generation-owning LSE through the allocation of high deficiency charges paid by other LSEs unable to contract with capacity because

and ISO-NE monthly ICAP markets, the demand for capacity is fixed at the planning reserve margin target corresponding to the regional reliability requirement (1-day in 10-years LOLE), and the supply for capacity is almost fixed, since it is relatively inelastic in the short run. The ICAP markets were thus characterized by a vertical demand curve and a near vertical supply curve in the region where supply crosses demand and sets the ICAP price. In this situation, a small amount of withholding can force a relatively large increase in price, especially if the amount of offered supply is fairly close to the planning reserve margin target, as shown in Figure 3.

Figure 3
Incentives to Exercise Market Power

The combination of a vertical demand curve and a near-vertical supply curve presents strong incentives to exercise market power.

- Any withheld supply shifts the Supply curve to the left
- A slight shift of the supply curve to the left causes a large increase in price.
- This can easily offset the revenues foregone as a result of withholding.

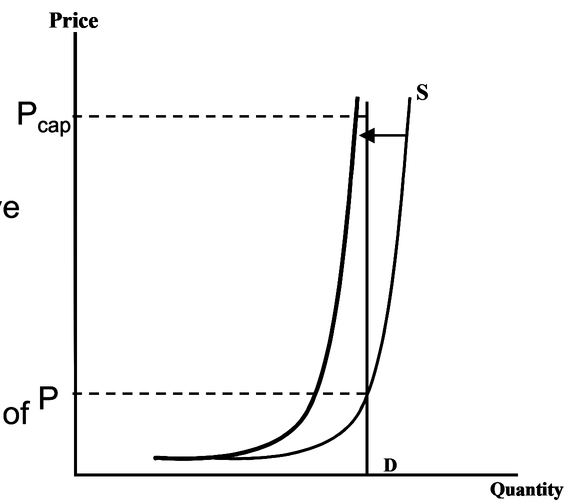

Figure 3 also illustrates that capacity markets characterized by vertical demand curves and near vertical supply curves in the short run can exhibit extreme price volatility. When supplies slightly exceed the fixed reserve requirement, capacity prices in the monthly markets can fall close to zero and remain near zero as long as there is just enough capacity to meet the fixed reserve requirement. (This partly explains the near-zero capacity prices observed in these markets, as shown in Figure 2.) But when supplies are slightly less than the fixed reserve requirement, capacity prices rise rapidly to the administrative price cap for capacity (sometimes called the "deficiency charge"). Extreme price volatility for capacity can create risks for both LSEs and their consumers. It can also increase investment risks for those contemplating capacity

of the contrived capacity shortage. In PJM, these penalty revenues were allocated to those LSEs who were fully covered with ICAP contracts. But these might be LSEs that were also large generation owners with incentives to withhold their surplus capacity. See, MMU, "Report to the Pennsylvania Public Utility Commission, Capacity Market Questions," November 2001.

additions when suppliers are near the reserve target, since a relative small change in the quantity can dramatically lower prices and eliminate expected returns on investment. And because the volatility is highly unpredictable, both buyers and sellers face risks in defining a capacity price for forward contracts.

There are several approaches for discouraging or mitigating market power in the ICAP markets. The focus here is on two particular options developed by the ISOs:

(1) *Change the demand curve*. The profits from exercising market power can be reduced by replacing the vertical demand curve with a downward sloping demand curve.[26] This is the approach pioneered by the NY ISO; it is now proposed in both ISO-NE and PJM. (The derivation of these curves is described later in this paper.) Note however, that although the profits from withholding would be reduced by the sloped curve, they would not be eliminated; hence there remains some incentive and opportunity to exercise market power through either physical or economic withholding of capacity. In the PJM and ISO-NE proposals, concern for this residual opportunity gives rise to further efforts to reduce market power if the ISO relies primarily on the downward sloping demand curve and monthly ICAP auctions to set ICAP prices. In the case of PJM, a principal method is to mitigate capacity offer prices in the periodic auctions or to compel suppliers to submit offers; in the case of ISO-NE, the proposed method is to count all installed capacity (net of exports), whether or not it is offered in the monthly auction, when setting the price from the demand curve. These approaches are described further below.

(2) *Change the supply curve*. Market power might also be reduced or eliminated by moving the obligation period sufficiently forward to allow new entry to occur; in effect this extends the supply curve to the right. This approach redefines the capacity product to be offered in each auction as a product that does not have to be "delivered" until three or four years from the auction date. The extended period gives new entrants sufficient time to permit and build new capacity, potentially undermining any attempt to withhold existing capacity from the auction. This approach was developed in a joint study prepared by NERA for PJM, NY-ISO and ISO-NE.[27] The concept is now part of the PJM reform proposal called "Reliability Pricing Model." So far, neither NYISO nor ISO-NE has proposed this forward obligation auction approach, although there has been some interest among New England intervenors who oppose the ISO-NE LICAP proposal.[28]

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[26] This approach is sometimes called the "demand curve" approach, but more accurately, it might be called the "*downward sloping* demand curve" approach. The current markets all use "demand curves," but in PJM and ISO-NE, the current "curves" are vertical, reflecting a fixed reserve requirement that does not change depending on price.

[27] Meehan, Eugene; LaCasse, Chantale; Kalmus, Philip; Neenan, Bernard. *Central Resource Adequacy Markets for PJM, NI-ISO and NE-ISO*. Prepared by NERA. February 2003.

[28] Maine regulators originally suggested a version of this forward auction approach as an alternative to the ISO-NE downward sloping demand curve. Another version of the forward obligation approach, based on an auction for option contracts, was offered by Connecticut parties in the LICAP hearings, but it was excluded by the ALJ as beyond the scope of the hearings, on the grounds that FERC's June 2, 2004 Order had limited the hearings primarily to how the parameters of the ISO demand curve should be selected. See *Initial Decision* 111 FERC ¶ 63,063 (Initial Decision) at 157-158. However, at a September 20, 2005 hearing for oral argument in the LICAP case, FERC allowed parties to describe alternatives to the ISO-NE LICAP proposal. In that hearing, regulators for four of the six

6. Uncertainty of capacity availability when it is most needed

ISO capacity markets in the East originally counted all "installed" capacity (hence "ICAP") towards meeting the fixed reserve requirements. However, capacity is not always available, and different units may have different levels of availability based on several factors. To partly account for these differences, the ISOs, beginning with PJM, developed the concept of "unforced capacity" or "UCAP." A unit's UCAP rating is a way to discount the capacity for which a given unit is given credit (or is entitled to sell) by adjusting its ICAP rating by a measure of its forced outages. For example, a unit with a nominal capacity of 100 MW might have an effective forced outage rate (EFORd) of 10 percent, suggesting that *on average*, the 100 MW unit had 90 MW of UCAP available. Given its UCAP rating, the unit would receive capacity payments for 90 MW, rather than 100 MW.

A UCAP rating would account for average availability over the year (or over a season), but it would not tell the ISO whether a plant was actually available in those hours in which the capacity was most needed, such as those hours when the operating reserves available to the ISO fell below the target reserve level. The ISOs therefore needed an additional mechanism to encourage generators to make their capacity available. Two mechanisms have been used by the eastern ISOs:

(1) *A must offer requirement*. Eastern ISO rules generally require any unit that wishes to receive capacity payments to offer its capacity to the ISO in the day-ahead market. To meet this requirement, the unit must either schedule (through a self-schedule or bilateral schedule) its capacity in the day-ahead market, submit an energy and/or operating reserve offer in the day-ahead market, or make its capacity available to the ISO's day-ahead unit commitment process.[29]

(2) *Penalties for failure to be available*. Any unit seeking to be paid for capacity that fails to meet the ISO's availability requirements (such as the must offer requirement) will incur a penalty charge set by the ISO market rules. The penalty is typically set at some fraction of the fixed costs of a combustion turbine, defined on an annual (or seasonal) basis. Units with approved maintenance schedules may be exempt from such penalties.[30]

The current availability requirements tend to suffer from several problems. First, the availability metric – UCAP adjusted for EFORd -- is an average. It fails to account for the

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New England states supported a form of the forward auction model with locational requirements (but no sloping demand curve) and the other two states' regulators supported the forward auction model but without locational requirements (and no sloping demand curve). For a description of the option contract auction proposal, see Bidwell, Miles, "Reliability Options," *, The Electricity Journal*, Volume 28, Issue 5, page 1.

[29] PJM Operating Agreement. Sheets 93-94. New England ISO Manual for Market Operations at 2-11.

[30] E.g., see NYISO Installed Capacity Manual 5.2 at 39-40. Available at http://www.nyiso.com/public/documents/manuals/planning.jsp

different value of capacity at different times and conditions, depending on how close the ISO is to falling short of capacity.

Second, the availability metric relies to some extent on self reporting by generators, but there may be an incentive for generators to not fully report outages that are not obvious. For example, if a unit is not dispatched on the day because its offer price is above the clearing prices for that day, but during that day the unit experiences a maintenance issue that would make it impossible to operate if it were actually called, it is not clear that the unit owner would report this as an outage that might affect its EFORd and UCAP. Having already concluded that the unit was not needed on that day, the ISO would have little reason to take steps to confirm the unit's operational availability.

Third, the penalties assessed for non-availability are administratively determined and fixed in the ISO tariff. But these penalties are unlikely to reflect the costs to the ISO of a unit's failure to be available. Limiting the penalties to some fraction or multiple of the annual cost of a CT is not likely to be the economically correct signal that reflects that unit's impact on market prices. Moreover, the energy market prices themselves are capped and hence do not reflect the value of shortages that may result from a unit's non-availability.

In its LICAP proposal, the ISO-NE is attempting to address this set of issues by changing the availability metric and moving to a market-based price for "penalties." As discussed below, ISO-NE proposes to replace the current UCAP/EFORd metric and instead measure availability by whether a unit is actually providing energy or operating reserves during an hour in which the ISO experiences a shortage in the target level of operating reserves. A unit unavailable during "reserve shortage hours" would see its capacity payments correspondingly reduced, while a unit that was available during those hours would see its capacity payments increased. The features of this reserve shortage hour metric and comparisons with the current UCAP/EFORd approach are described in more detail below.

7. Lack of Incentives for Features that Support Reliability (or Assure Availability)

A principal reason for the increased need for RMR contracts is the fact that current market rules and pricing mechanism may not sufficiently compensate generators that provide features and attributes essential for reliable operations or valuable to the ISO in implementing a reliable and economic dispatch. Some of these essential reliability features are simply not priced directly or at all in today's markets, such as voltage support or black start capability. Higher energy prices alone cannot provide the appropriate incentives for the supply of these services, and additional markets or pricing mechanisms would seem necessary.

Efficient energy and/or operating reserve pricing, however, could encourage other features, but the incentives are blunted by price and offer caps or other rules that suppress energy market prices below competitive levels or by the absence of effective markets for operating reserves. For example, efficient market-clearing prices during reserve shortage hours would reflect the shortage and thus tend to be high enough to encourage investments and operational decisions that make it more likely that a unit would be available when needed. Such prices might, for example, encourage more investments in quick-start units, or units that could be cycled on/off more often, or units with faster ramping rates; they might also encourage unit owners to change their fuel purchasing habits to ensure fuel during expected peak conditions or reserve shortage hours or to invest in dual-fuel capabilities to manage the risks of gas shortages during winter peak periods, and so on. However, since price/offer caps limit the level of energy prices during these same periods, they also blunt the incentives to take these and other steps that allow generators to be available when they are most needed.

As currently structured, ICAP payments do not solve these problems, because the UCAP availability metric measures average availability and because the administrative penalty structure does not necessarily mimic the incentive properties of uncapped shortage-cost pricing. As a result, the incentives for both operational and investments decisions that affect real-time availability are not efficient, likely resulting in a more costly mix of generator characteristics than those that would minimize the cost of maintaining reliable operations.

In their reform efforts, PJM and ISO-NE have approached this incentive problem in two very different ways. The PJM approach is to have the ISO identify specific generation features that it would like to encourage – such as quick-start capability and dispatch flexibility – and specifically reward those identified characteristics in the ICAP auctions. Those units that have the selected features are paid a higher price in the auction; those without them are paid less. Since the ISO makes the choice of which features to reward, this has the characteristics of an integrated planning approach, but it also means that other measures that might also be valuable for maintaining reliability may not be undertaken, because they are not explicitly rewarded.

In contrast, the ISO-NE proposed approach is to measure availability based on whether a unit was actually available during those hours in which the ISO falls below its target level of operating reserves. Compensation then depends on whether a unit was or was not providing energy and/or operating reserves during these stressed hours. Since compensation depends on actual availability during these hours, the concept attempts to provide a strong market signal to generators to make whatever steps and investments they think are justified to improve the changes of actual availability. Under this approach, the ISO does not attempt to single out specific features to reward; rather, its goal is to reward any combination of features that enhances actual availability of units when they are most needed. Unlike the integrating planning model proposed by PJM, the choice of which mix of measures to pursue is left to the generators and the market to sort out. These contrasting concepts are discussed in more detail below.

The Sections that follow describe the ISO-NE and PJM proposals in more detail. The discussion is organized to focus on how each ISO attempts to address the several concerns above.

THE ISO-NEW ENGLAND LICAP PROPOSAL

The ISO-NE filed its original LICAP proposal at FERC on March 1, 2004.[31] This original version was revised following a FERC Order approving the two key elements, a locational ICAP market and the use of a downward sloping demand curve, and suggesting a separate LICAP zone for Southwest Connecticut.[32] The ISO subsequently proposed a separate LICAP zone for that area, which FERC approved.[33] In its June 2, 2004 Order, FERC set the specific design parameters of the curve and a limited number of other issues for hearings, which began in late 2004. When the ISO filed its initial testimony for these hearings on November 4, 2005, the ISO further refined key parameters of its proposed demand curve, and it is this revised version of the curve, and further changes in other features introduced in ISO-NE rebuttal testimony, that are discussed below.

The original ISO filing contained most of the elements of the current proposal, and one additional feature – a four-year phase in for LICAP payments -- that the ISO hoped would attract support for the overall LICAP mechanism from load serving entities and New England regulators. During the phase in, LICAP payments would be initially capped, with the caps rising each year, to avoid a one-time rate shock. At the same time, additional compensation would be provided directly to generators in each region, with the costs recovered from loads in the respective regions.[34] The phase in features failed to entice parties into supporting the ISO proposal, and this feature was not endorsed by the FERC June 2, 2004 Order. ISO-NE did not pursue a phase in or other transition feature thereafter.[35]

There are five major components of the ISO-NE LICAP proposal.

1. *The ICAP structure would be locational*. As the term "LICAP" implies, the ICAP structure in New England would recognize five different Locational ICAP zones in which ICAP prices could be different. The five zones include (1) Maine, which is recognized as a transmission constrained generation pocket, (2) the Northeast Massachusetts (NEMA) and Boston region, an area generally recognized as a transmission constrained load pocket, (3) Connecticut, into which there is limited transmission capacity from the rest of New England, (4) Southwest Connecticut, into which serious transmission constraints limit the transfer of power even from the rest of Connecticut, and (5) the rest of ISO-NE footprint ("rest of pool"). The designation of LICAP zones implies the need to define how much of the capacity

[31] *Compliance Filing of ISO New England Inc.; Devon Power LLC, et al* in FERC Docket ER03-563-030 (March 1, 2004 Filing).

[32] FERC, *Order on Compliance Filings and Establishing Hearing Procedures* in Dockets ER03-563-030 and ELO4-102-000 (June 2, 2004 Order).

[33] *Compliance Filings of ISO New England, Inc.* July 2, 2004 in FERC Dockets ER03-563-039 and EL04-102-002 (July 2, 2004 Filing)

[34] March 1, 2004 Filing, at 6.

[35] Appendix B contains a timeline and summaries of relevant ISO-NE filings and FERC Orders.

needed to meet an area's reliability requirement must be located inside each zone and how much can be imported from the rest of New England, a neighboring zone or neighboring ISO or control area. It also implies some method to allocate the rights to that import capability, either on a financial or physical basis. These issues are developed further below.

2. *The LICAP mechanism would use a downward sloping demand curve*. The downward sloping curve would replace the existing vertical curve, which is based on a fixed planning reserve requirement defined by the region's 1-day in 10-year LOLE reliability criterion. A downward sloping curve implies that the level of capacity reserves varies with price, reflecting the intuitive notion that if capacity is cheap, consumers might be willing to buy more than the target level of capacity, but if capacity is expensive, consumers might be willing to buy less than the target level of capacity. It also reflects the notion that levels of reserves higher than a nominal reserve target have some positive reliability value (hence the value of incremental capacity is not zero), while capacity has a higher value when reserve levels are below (less than) the reserve target. In specifying the curve, the ISO also expanded the definition of the region's reliability standard. That is, the curve is designed not only to achieve the 1-day in 10-year LOLE, on average, but also to ensure that the level of capacity does not fall below the level required to meet the 1-day in 10-year LOLE criterion more often than has been historically the case over the last two decades. The design details and rationale of the ISO-NE's proposed demand curve, and responses from stakeholders to its various parameters, are described further below.

3. *The ISO-NE proposal significantly changes the availability metric to encourage availability during reserves shortage hours*. Under the proposal, generators would begin with a capacity rating adjusted by forced outage rates (EFORd), just as occurs under the current UCAP approach. However, this initial rating for each unit would thereafter be adjusted up or down depending on whether the unit was or was not "available" during each hour in which the ISO experienced a shortage of operating reserves.[36] The updating of the availability factor would occur after each shortage hour, and the result at the end of the month would be applied to payments in the following month. The intended effect would be to reward generators that are actually available during those hours in which their energy is most needed for reliability and most valuable to the ISO, and to penalize generators that, *for almost any reason*, are not available during those stressed hours.[37] In this context, "available" means the unit is either producing energy during that hour or providing operating reserves (or is capable of providing such reserves, such as a unit that can start up within 30 minutes). A formula would be

[36] An operating reserve shortage hour is any hour for which the operating reserves available to the ISO fall below the threshold defined by ISO Operating Procedure 4 *ISO New England Operating Procedures*. February 1, 2005.

[37] The ISO-NE has not developed final rules for its proposal, so it is unclear whether there would be any exceptions to this general rule. During the hearings, ISO-NE witnesses generally took the view that there would be few if any exceptions.

used to calculate the up or down adjustments in each unit's availability factor after each reserve shortage hour. Further details about this approach and some of the issues it raises are discussed below.

4. *The proposal would count all capacity in defining the LICAP price*. The ISO added this feature to address arguments offered during the hearings by FERC Staff that even with a downward sloping demand curve, generators might still be able to exercise market power through physical or economic withholding. Under existing ICAP rules, generators offer their capacity in the monthly or seasonal (New York) ICAP auctions, and prices are defined where the supply curve formed by such capacity offers crosses the demand curve for capacity. Physically withholding capacity from the auction could therefore raise the clearing price,[38] and so could higher capacity offer prices. To avoid this result, the ISO-NE pricing mechanism would count all ICAP in the region, including imports and net of exports. Capacity would be counted whether or not it was offered in the auction and even if it was temporarily mothballed. The point where this total quantity of ICAP meets the downward sloping curve would define the auction price for LICAP. Generators would still submit price offers in the monthly auction, but these offers would *not* define the auction price; they would merely determine which offers were accepted – that is, which generators sold capacity in that month's auction and which would be paid, but not how much they would be paid. This feature and its attributes are discussed further below.

5. *LICAP payments would be reduced by profits earned in the energy markets by the "benchmark" unit.* Recall that a central purpose of an ICAP payment is to replace the "missing money" resulting from the caps on spot energy prices. Capacity payments should thus allow recovery of a unit's fixed costs. But generators dispatched in the energy markets could also receive a contribution to their fixed costs from energy prices; the contribution would be the difference between the clearing price at their location (LMP) and their operating costs. The remainder of a unit's fixed cost would need to be recovered through the ICAP payment. Therefore, to ensure that generators are not paid twice for that portion of the fixed costs covered by the energy prices, the ISO-NE proposal reduces the LICAP payments, as defined in each month's LICAP auction, by the profits that would be earned in the energy market by the "benchmark" generator during peak hours. This amount is called the "peak energy rental" (PER) in the ISO-NE proposal.[39] In general, the payment to each generator eligible for LICAP payments is the LICAP price for that month minus the PER for the benchmark generator. The LICAP payment would be further adjusted by each generator's availability factor for that month, which would be recalculated after each shortage

[38] How much it would raise the ICAP price would depend partly on the slope of the curve. A steeper slope leads to a larger change in price for any given change in quantity; a flatter slope leads to a smaller change in price for the same change in quantity.

[39] ISO-NE defines the "benchmark" generator as a frame simple cycle combustion turbine unit.

hour and applied for the subsequent months to reflect whether or not that unit was available during any reserve shortage hour that occurred in the prior month.[40]

Design of the ISO-NE Demand Curve

A defining characteristic of the ISO-NE proposed demand curve is that it is administratively designed. The curve is not the product of actual consumers/buyers expressing a willingness to pay various prices for various quantities of capacity. The latter approach is not possible, *given* the starting point of capped energy prices, the general absence of real-time pricing and corresponding lack of demand-side response. In other words, by accepting energy market price caps as a practical or political necessity, and lacking the support to pass even capped hourly spot prices through to end use consumers, the ISO begins with a condition in which consumers/buyers are not able to indicate how much they would be willing to pay for different levels of capacity or reliability. Given these constraints, there is no clear mechanism for consumers/buyers to indicate their individual value of lost load (VOLL) – that is, the prices each of them would be willing to pay to avoid involuntary curtailments. In the absence of this critical market information, any "demand curve" used to define prices must be specified administratively.[41]

In the case of the ISO-NE demand curve, the parameters of the curve were specified primarily by the ISO, but with an implicit recognition of the role of state regulators as holding the proxy for consumers. How consumers' wishes are properly represented, and by whom, can be controversial, as shown by the universal opposition to the ISO's proposed curve by the utility regulatory commissions for each of the six New England states. The opposition reasons are discussed further below. For the moment, the focus is on how the ISO specified a curve that, it claims, is consistent with accepted regional reliability standards.

A second essential design feature of the ISO-NE demand curve is that there is an intended link between the curve's specifications and the investment requirements for the level of reserves corresponding to the region's reliability objectives. The curve is designed such that *on average* the monthly ICAP payments derived from the curve would provide the ISO's estimate of the missing contribution to fixed costs that investors would need to break even when the level of reserve capacity satisfies the regional reliability objective.[42] According to the ISO's witness, the explicit link between the curve's design and the reliability goal is important because it means that changes in any individual parameter of the curve may affect the amount of investment likely to occur and hence whether it does or does not meet a given reliability standard. Different parameters can result in different curves, and other curves may be reasonable, but to meet the

[40] If no reserve shortage hours occurred during the prior month, each unit's availability factor would not change from the prior month.

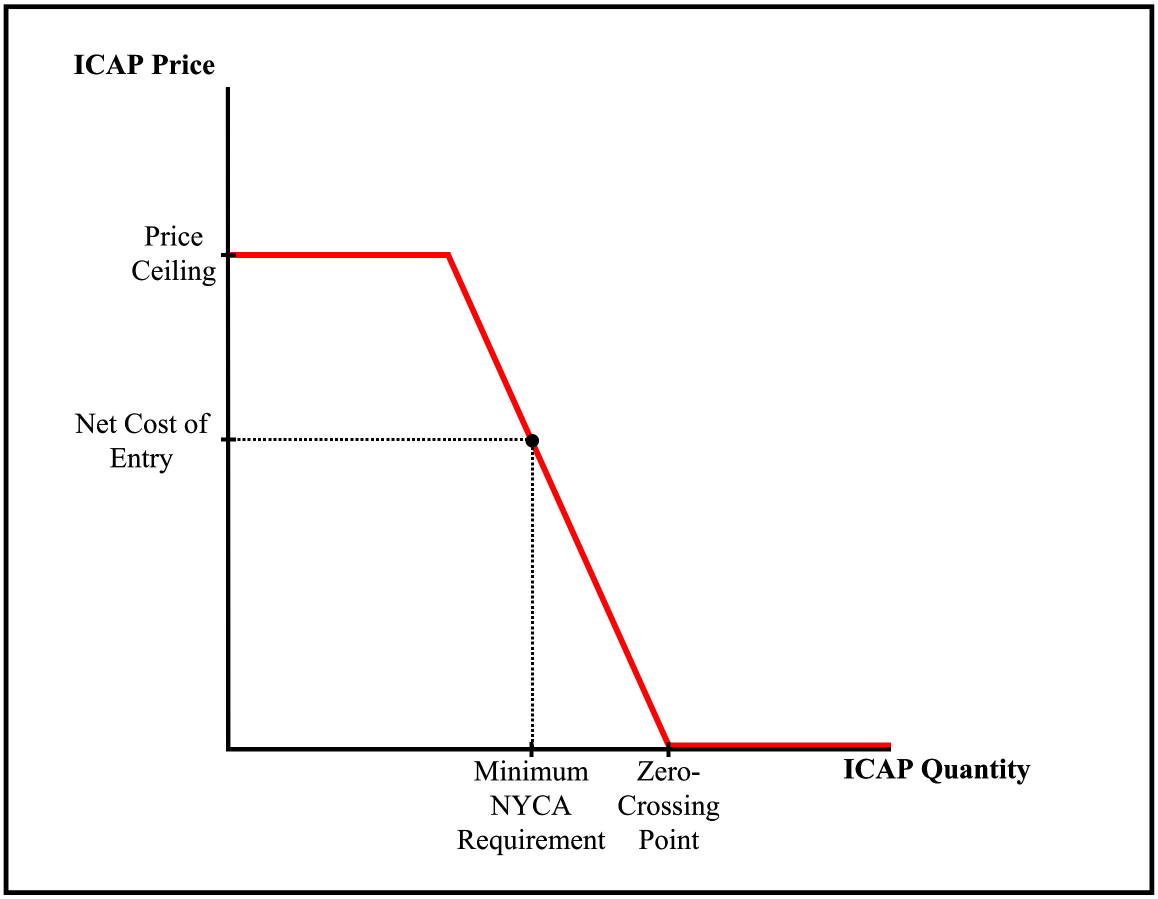
[41] See, *Prepared Rebuttal Testimony of Steven Stoft on Behalf of ISO New England Inc*, in FERC Docket ER03-563-030, February 10, 2005 (Stoft Rebuttal). Similar arguments appear in the California PUC Staff White Paper at 4. The Hogan paper returns to this question and examines how an uncapped energy market might function if these imposed constraints were removed.

[42] See, *Prepared Direct Testimony of Steven Stoft on Behalf of ISO New England*, in FERC Docket ER03-563-030, (Stoft Direct) at 16-17. Compare California PUC Staff White Paperat 18-20. In the White Paper, this type of curve is called a "Fixed Cost Recovery" curve.

same reliability standard, any change in one parameter may need to be offset by compensating changes in one or more other parameters.[43]

The ISO-NE proposed demand curve is a refinement of the concepts underlying the New York ISO demand curves. To understand these refinements, consider first the basic features of the NY ISO curve. Figure 4 illustrates the key features.[44]

Figure 4
NYISO ICAP Demand Curve



The New York demand curve is drawn by specifying a few key parameters, and then basically connecting the dots. The key parameters shown in Figure X are:

(1) The reliability goal or standard. It is shown here as "minimum NYCA requirement," which is the level of reserves above expected peak demand necessary to meet the 1-day in 10-year LOLE adopted by the New York State

[43] Stoft Rebuttal at 37:7-20.

[44] This is a generic curve to illustrate the concepts. Further description of the current NY ISO demand curves appears in Harvey, "ICAP Systems in the Northeast: Trends and Lessons," at p. 51-60.

Reliability Council, which has responsibility for setting reliability standards in New York.

(2) The "net cost of entry," for the type of capacity assumed to be the lowest cost way to add new capacity. As in other ISO ICAP markets, the assumed benchmark unit is a frame, simple cycle combustion turbine. The "cost of entry" is the monthly fixed cost of that capacity, in $/MW-month. The "net" aspect is an adjustment to reflect the peak energy rentals that would be earned by that unit in the energy markets. The NY ISO uses a forecast of such rentals.[45] In the ISO-NE curve, the "cost of entry" concept is captured by the term, "EBCC," which standards for the ISO's estimate of the benchmark unit's capital cost. As discussed below, however, the ISO-NE approach does not net out the peak energy rentals at this point; instead it subtracts these peak energy rentals for the benchmark unit when it determines the LICAP payments, in an effort to achieve a similar purpose.

(3) The first point of the curve is thus the intersection of the two previous parameters: the net cost of entry and the minimum NYCA requirement. The curve can now be drawn through this point. This point can be understood as defining the break-even point for investment. If the level of capacity is at this level (the minimum requirement), the ICAP payment defined by the curve would be exactly the amount needed to cover the net fixed costs of that level of investment, no more, and no less (assuming that the ISO accurately estimated the net cost of entry).

(4) The next point on the New York curve is the "zero crossing point." In the ISO-NE curve, this point will be called C_{max}. It refers to that level of reserves when price falls to zero. Reserve levels less than (to the left of) that point will receive some positive ICAP payment; but if reserves equal or exceed that amount, ICAP payments will be zero. The concept is that once the region has this amount of excess capacity beyond its minimum or target level, capacity has no value and no generator receives any capacity payment.

(5) The final point on the cure is defined by what is, in effect, a price cap on capacity. In the NY curve, it is called Pricing Ceiling; in the ISO-NE curve, the same idea is represented by some multiple of EBCC. For the original NY curve, this cap was about 1.5 times the net cost of entry; in the ISO-NE curve, the proposed cap is 2.0 times the EBCC.

Given these few key parameters, the ISO can draw the curve connecting the points, as shown in Figure X above. In each monthly UCAP auction, generators in New York offer their

[45] The "net" aspect is based on a forecast of the revenues that the hypothetical CT unit would earn over the course of a year from the sales of energy and ancillary services, over and above the costs associated with providing the energy and ancillary services, if conditions were at the long-run equilibrium (i.e., the amount of capacity in the state was equal to the minimum capacity requirement, both statewide and in the New York City and Long Island regions). The New York ISO uses a model to estimate these net revenues.

capacity at various prices, and the ICAP payments are defined by the intersection of the resulting supply curve and the administratively defined demand curve. Generators whose capacity clears the auction receive the auction clearing price for their zone for that capacity. LSEs that are short of capacity coming into the auction pay the ICAP price for the amount of megawatts to cover their shortage; LSEs with excess capacity that clears the auction receive the ICAP price for that capacity.

Deriving each of these points requires an administrative process. For example, the ISO studies the costs of constructing and operating a CT, and the ISO develops estimates of the expected revenues that a combustion turbine unit would receive in the capped energy markets. The minimum requirement is set by whatever authority is responsible for setting reliability standards, in the New York case, the Northeast Power Coordinating Council and the New York State Reliability Council.[46] In ISO-NE, this would be the Northeast Power Coordinating Council (NPCC); in PJM, it would be PJM acting in lieu of, or conjunction with the regional reliability councils of MAAC, ECAR, MAIN and SERC. The capacity price cap and the zero crossing point are matters of judgment, based partly on how steep the ISO wants the curve to be, but also bearing in mind the total investment objective defined by the curve.

The slope of the curve affects the strength of incentives to invest in new capacity or retire existing capacity. But the slope is defined by where the entity drawing the curve sets the zero crossing point and the capacity price cap. Moving the zero crossing point to the left while keeping other parameters constant, for example, would make the curve steeper (or end payments for capacity sooner, as will be seen in the PJM curve), while moving it to the right would make it flatter. A steeper curve would more rapidly increase incentives to invest (relative to a flatter slope) when reserves are less than the minimum requirement, because the prices rise faster as shortages increase; a steeper curve on the right side of the break-even point also increases the incentives to retire costly units when reserves are above the minimum, because prices fall quickly below the break-even point. Similarly, a higher capacity price cap would increase the incentive to invest when reserves fall further below the minimum requirement. At the same time, a steeper curve on the right side may also increase the risks of investing even a little too much; with a steeper curve, a small amount of overbuilding risks failing to receive capacity payments sufficient to break even on the investment.

Loads and generators might therefore perceive the key parameters in different ways, requiring the ISO (or FERC) to take a more detached view and/or arbitrate the conflicting stakeholder positions. Loads (and state regulators), for example, might be concerned that very high ICAP price caps would increase the incentives to exercise market power through withholding. The steeper the curve, the higher the potential profits from withholding when reserve levels are above the minimum requirement, unless market power is addressed in some other way.[47] Generators, on the other hand, might point out that a very flat curve with a low price cap could significantly undermine both incentives to invest when reserves were below the minimum required and the incentives to retire when reserves were above the minimum.

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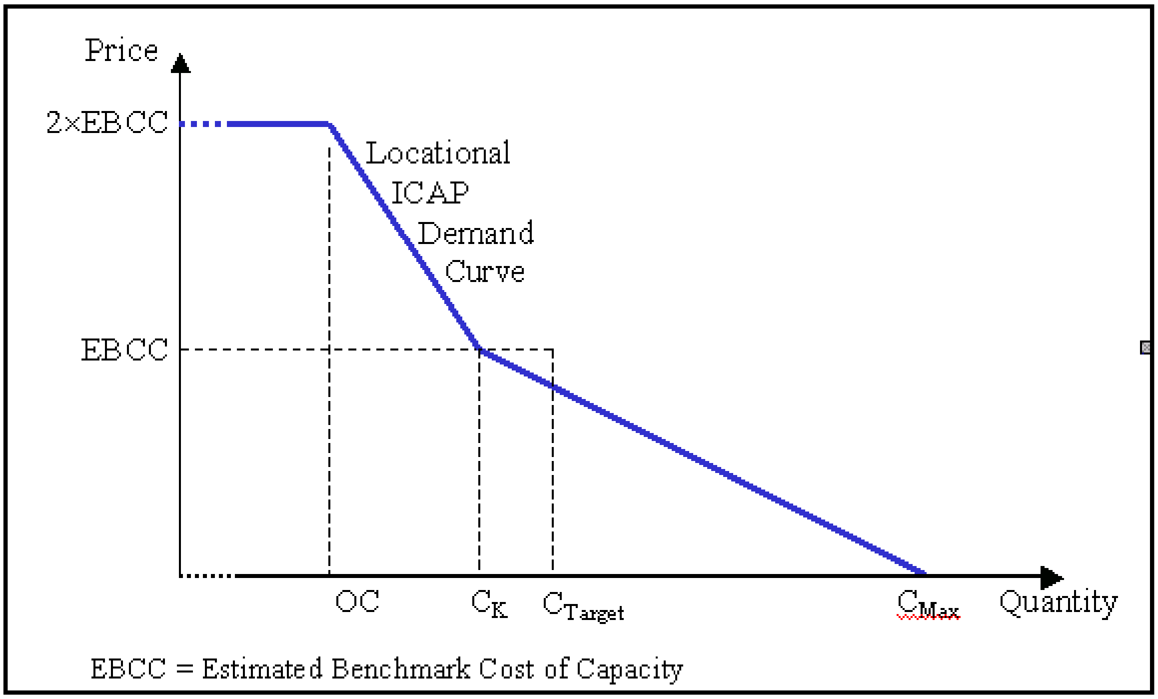
[46] The 1-day in 10-year criteria for NPCC is specified in NPCC's "Basic Criteria for Design and Operation of Interconnected Power Systems, 3.0 Resource Adequacy – Design Criteria."

[47] The highest profits would occur if the curve were vertical.

These considerations affected the ISO-NE's thinking about how to design the New England demand curve.   The ISO-NE's proposed demand curve is illustrated in Figure 5.

Figure 5
Proposed ISO-NE Demand Curve



Comparing Figure 4 and Figure 5, each of the parameters of the NY demand curve has a counterpart in the ISO-NE demand curve, but in the New England curve, there are additional parameters, and the parameters are sometimes derived in different ways.   There is more apparent complexity, and the design goals of the curve have expanded. The key parameters in the proposed New England curve are:

(1) A more complex statement of the reliability standard. In the ISO-NE proposed curve, there are now three parameters – OC, C_k and C_{Target} -- that are intended to interact in pursuit of a level of investment that will meet the desired reliability standard.

(2) The level of reserves that corresponds to the 1-day in 10-year LOLE criterion is called "objective capability" or "OC" in New England; it is called the "minimum NY CA requirement" in New York.

(3) There is a "kink" in the demand curve. The level of reserves at that point is called C_k, and that level is a few percentage points higher than the reserve margin defined by OC. The purpose of the kink is to split the curve into two parts: on the left side, the slope of the curve is steeper; on the right side, the slope of the curve is flatter, with

the intent to balance different design objectives. The intent on the left is to increase incentives for the market to invest in new capacity when the reserve levels fall below the reliability target; the primary intent on the right is to reduce the risks to investors of slightly overshooting the breakeven point, so that on average, investors are more likely to reach the target reserve level.[48] The placement of C_k thus takes on special importance, because it implies that the value of incremental capacity rises rapidly for levels of capacity less than C_k, while the value of capacity declines slowly for levels of capacity greater than C_k.[49]

(4) The curve also specifies C_{max}, which corresponds to the "zero crossing point" in the NY demand curve. In the NY approach, the zero crossing point is explicitly selected; in the ISO-NE approach, C_{max} is derivative of the slopes around C_k. In other words, the curve's designer uses judgment to decide the ratio of the left side slope to the right side slope, given their respective goals. In this case, the chosen ratio is 3:1, so given these slopes, the slope on the right side of the demand curve defines the zero crossing point at C_{max}.

(5) EBCC represents the estimated break-even point for the capital (and fixed operating) costs of the benchmark unit. As in NY, the benchmark unit used by the ISO is a frame combustion turbine. Since there would be at least five different LICAP regions, there are five curves based on five different EBCCs, reflecting the different estimates of costs of building a CT in each region.[50]

(6) The next point is the price cap. In the ISO-NE curve, this cap is set at twice the value of EBCC. Setting it at this level (as opposed to 1.5 times EBCC or some other value) appears to have been a matter of judgment, with the designer focused on the desire to send a strong investment signal when capacity levels are below the target level. The price cap level is also sensitive to the other parameters. For example, a lower cap would make the left-side slope flatter and thus reduce incentives to invest when reserve levels are less than the capacity target; to make up for this reduced incentive to build capacity when needed, the designer might change another parameter to

[48] Stoft Direct at 15:17-20; Stoft Rebuttal at 42:22-23.

[49] As noted above, the designer's intent behind the different slopes is to provide stronger investment signals when capacity levels fall below the desired level while reducing investment risks when adding capacity that might exceed the desired level. See, Stoft Direct, at 15:17-20. Dr. Stoft also makes a theoretical argument for this difference in assumed values in Stoft, *Power System Economics Designing Markets for Electricity.* Wiley-IEEE Press, New York City, New York: 2002.

[50] Some generators in the LICAP proceeding argued that the more costly aeroderivative unit, rather than the frame CT, should be used as the benchmark unit in constrained local areas. They argued that aeroderivative units should be the benchmark for small, constrained regions, as they are physically smaller, easier to cite in constrained regions, and may require fewer regulatory approvals than frames, which they propose be used as benchmark technology for larger regions. These parties also assert that using the aeroderivative unit as the benchmark will send more timely and efficient signals to new market entrants in constrained areas. However, the FERC ALJ rejected using these units for the benchmark. Initial Decision at 157-158.

encourage more investment or discourage retirement, such as by moving C_{max} further to the right.[51]

(7) Given the parameters of the price cap (2 X EBCC), OC, C_k and C_{max} (derived from the slope to the right of C_k), it is now possible to draw the ISO-NE proposed demand curve shown in Figure 5. *However, its placement requires one more parameter*.

There is still one parameter, C_{target}, to be defined. This parameter defines the region's target level of reserves, *on average*, given the expected variability of reserves relative to OC over time. This notion recognizes that the region cannot achieve OC – the level of reserves consistent with 1-day in 10-year LOLE criterion – exactly each year. Peak demand will vary and differ from forecasts, and capacity levels will change as new units enter the system and older units retire. In some years the resulting capacity reserve levels will be above OC; in other years the reserve margins will be below OC. The ISO therefore reasoned that knowing the reliability criterion (OC) was not sufficient by itself; the ISO still needed to determine how much, or how often, the level of reserves should fall below OC, because that would affect the placement of the curve. As stated by ISO witness Dave LaPlante,

> "The implementation of a demand curve requires us to develop a standard that addresses changes in load and capacity values from year to year."[52]

The ISO also reasoned that the costs to consumers of falling below OC by a given percentage would be significantly higher than the costs of going above OC by the same percentage. This conclusion is premised on the argument that the economic costs of involuntary curtailments can be very high, while the costs of a little excess generation would add relatively little to overall electricity rates.[53]

To derive C_{target}, the ISO attempted to determine a "regional reliability standard" that it believed would be consistent with the level of reliability historically achieved in the New England region. The ISO examined the available data on reserve levels relative to OC for the previous 21 years (apparently, the only years for which such data were available). Based on this data, the ISO found that reserves have been above OC in most of the years, and below OC in only 3 years, or about 14 percent of the years. A further statistical analysis of the same data showed an approximately normal distribution of capacity around a level of capacity higher than

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[51] Stoft Rebuttal at 6:15-21. In the LICAP hearings, parties representing loads tended to urge changes to individual parameters in ways that all resulted in less total investment or lower payments; generator parties tended to change individual parameters in ways that all resulted in more investment and higher payments. According to the ISO, the results were that changes recommended by loads systematically failed to meet the reliability goal, while changes recommended by generators systematically increased likely investment levels far beyond the reliability goal.

[52] LaPlante Rebuttal at 28-30.

[53] Hence the argument concludes that the costs of an increased probability of involuntary rolling blackouts, when falling below OC, is more than the cost of exceeding OC by the same amount. Note that this argument depends somewhat on the assumption that OC itself reflects an economically desirable level of reserves, even though the 1-day in 10-year LOLE criterion is essentially an engineering standard and is not based on estimates of the value of lost load. On the other hand, the ISO might argue that by accepting this criterion for so long, utilities and regulators have implicitly accepted its economic justification.

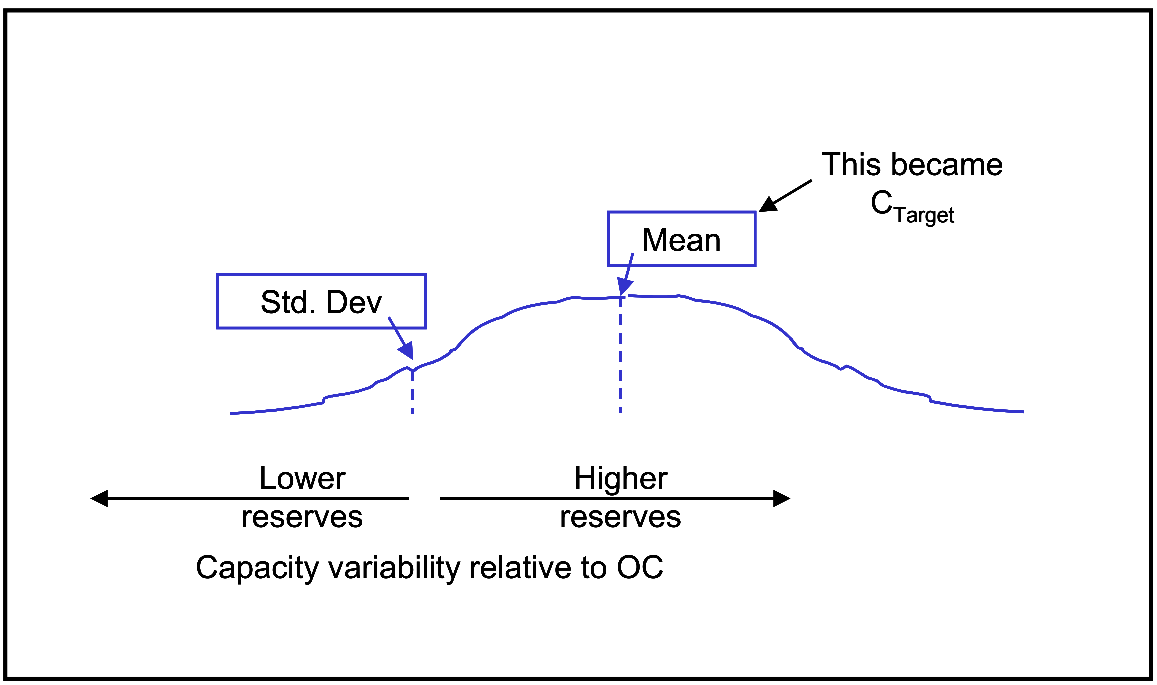
OC. Taking the standard deviation, the ISO argued that to achieve the historic level of reliability, the region should not allow reserves to fall below OC more than 17 percent of the time. It then used this finding to define the average target level of capacity, or C_{target}, which occurs at the mean of the expected distribution.[54]

As described by the Dave LaPlante, capacity variation in the past was distributed around a mean value somewhat higher than OC.

> "The data showed that the average surplus over this period was 105.4% above OC and that the standard deviation of the surplus during that time period was 5.8%. Assuming the distribution of annual capacity surplus to be a normal distribution with a mean of 1.054 and a standard deviation of 0.058, one can expect to be below OC roughly 17 % of the time."[55]

Figure 6 illustrates the concept of the historic variation in capacity levels around a level of capacity higher than OC and the resulting derivation of C_{target}.

Figure 6
Historic Variability of Capacity
Relative to OC

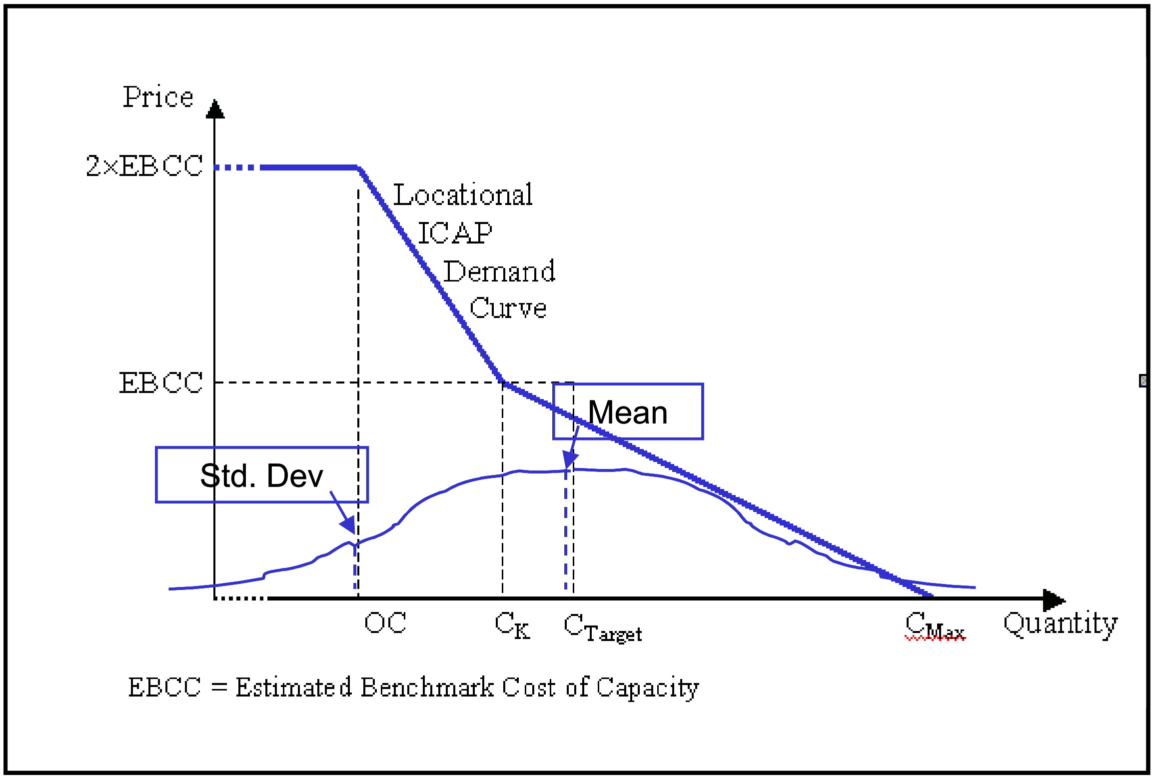


[54] Stoft Direct at 78-79; LaPlante Rebuttal at 34.

[55] LaPlante Rebuttal at 34.

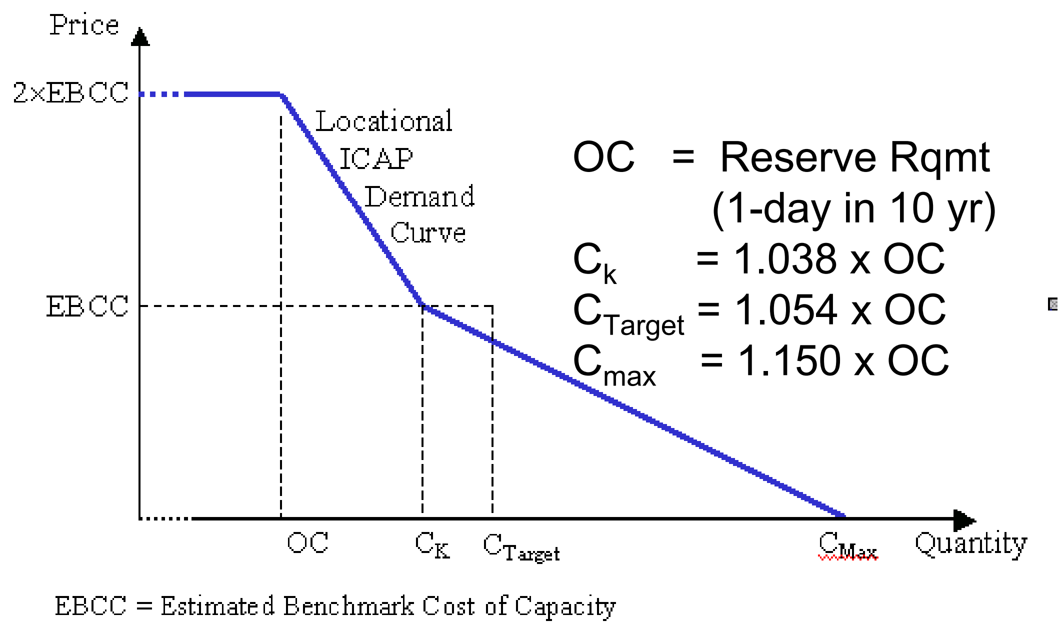
Using this capacity distribution from the past as a guide, the ISO defined the target level for capacity, as shown in Figure 7.

Figure 7
Historic Capacity Variability
Defined C-Target



In this figure, C_{target} is set at the mean defined by the historic distribution. The distribution is then placed at the point where the standard deviation reflected in the historic distribution equals OC. The placement of the curve is thus intended to achieve, on average, the same degree of compliance with the reliability standard as New England has experienced historically. In other words, if the region achieves C_{target} on average, *and* the variability of capacity relative to OC is about the same going forward as in the historic period examined by the ISO, then the region will not only surpass OC on average but it will also not fall below OC reserve levels more than 17 percent of the time. The ISO defined this goal as the "regional reliability standard" for New England. The resulting reserve margins relative to the 1-day in 10-year LOLE criterion are shown in Figure 8.

Figure 8
Reserves Margins above OC
Implied by ISO-NE Curve



Source: Stoft rebuttal, Exh ISO-36:17

Issues Concerning the ISO-NE Demand Curve

The ISO's use of the historic distribution of capacity for the proposed demand curve was premised on the argument that since this was the level of capacity achieved in the past, it could be used to define what the average target should be in the future.[56] The ISO argued that since utilities built this level of capacity and regulators approved this level in the pre-market regulatory regime, there was an implied acceptance of this level as the *de facto* reliability standard for New England. However, in the hearings, New England state regulators and parties representing loads argued against this assumption. These parties also argued that if the demand curve worked as well as the ISO hoped, then the variability of capacity would likely be lower in the future than it had been in past. However, these positions were not accepted by the ALJ in her Initial Decision.

Several parties agreed with Dr. Stoft that the new demand curve could reduce the variability of capacity, in part because the curve's incentive structure would encourage investment and retirement decisions that would move investors closer to OC with less variability than experienced under the prior regulatory and early market regimes. However, Stoft indicated that there was no assurance of this improvement and that in the absence of better empirical

[56] LaPlante Rebuttal at 32-33.

information, the only evidence to go on was historical performance. If actual performance under the curve improved over historic performance, then the standard deviation used to position the curve could be adjusted (moved to the left) in the future (ISO proposed annual updates, although load parties complained that even if observed variability decreased each year, the annual adjustments would be minor each time, because of the ISO's expressed desire to reduce regulatory uncertainty).[57]

The proposal to implement a downward sloping demand curve has general support among generators but virtually no support from parties representing loads in New England or from New England state regulators and public officials.[58] Perceptions about the effect of the demand curve approach on near-term capacity payments (for generators) and the resulting costs (for loads) probably explain these starkly contrasting positions.[59]

Under the current ISO-NE UCAP system, the ICAP price paid to generators in the monthly auctions is determined by a vertical demand curve. When there is even a small surplus of capacity over the reserve requirement, UCAP prices fall to very low levels, close to zero (see Figure 3, above). There is currently a surplus above the reserve requirement for the New England region as a whole.[60] As a result of this regional surplus, current monthly capacity prices throughout New England are very low, and these low spot capacity prices are reflected in low term contract prices (and likely lower demand for such contracts).

Under the ISO-NE's proposed downward sloping demand curve and the values for C_k, ICAP prices in the short run would likely be higher than current levels, although ICAP prices would remain below the estimated break-even point for recovering generators' fixed costs as long as the region was in surplus.[61] Hence, as soon as the ISO-NE proposal was implemented, generators across the region would receive higher ICAP payments, and loads would pay higher prices for capacity for purchases in the monthly ICAP markets. While loads might be hedged against increases in spot capacity prices through existing term contracts for capacity, in the long run one might reasonably expect forward prices and contract renewals to reflect the higher prices

[57] Stoft Rebuttal at 17-18.

[58] See Appendix B, which summarizes correspondence to FERC opposing LICAP in general, and the demand curve in particular, from New England state regulators, state Attorneys General and most of the New England Congressional delegation.

[59] Substantial opposition to LICAP also came from parties in Southwest Connecticut, who objected to the creation of a SW Connecticut LICAP zone, which they believed would result in higher ICAP payments for loads in that area than for the remainder of Connecticut or New England. Note, however, that the costs of the RMR contracts and costs of any new generation procured under an emergency RFP for that region would also be allocated to loads in the energy load zone containing the constrained region.

[60] While there is a *regional* surplus, there is little if any surplus in transmission constrained areas such as Southwest Connecticut. In such regions, any apparent surplus is maintained by counting units that are under RMR contracts but that might otherwise have retired without such contracts. The imminent need for additional resources in Southwest Connecticut has led to emergency RFPs for new capacity in that area and to accelerated efforts to build new transmission into and within that area.

[61] Current capacity levels are generally higher than C_k.

permitted under the downward sloping demand curve. While the long-run price of ICAP would have to equal the long-run cost of capacity in any case, load parties seemed focused on the short-run effect. It is not surprising, therefore, that load and state opposition to the LICAP approach focused on the prospects for higher near term prices under the proposed demand curve, resulting in requests that FERC deny approval or at least delay implementation for a year or more. These protests have already been partly effective in delaying the ISO's planned implementation date from June 1, 2006 to some yet to be determined date after the 2006 summer season.[62]

There is no dispute that, under current surplus conditions, a downward sloping ICAP curve will increase capacity payments in the near term compared to a vertical demand curve. However, it is not clear how much the total cost to loads would increase even in the short run. In the absence of LICAP and the downward sloping curve, the ISO would still need to provide compensation to plants needed for reliability that might otherwise be retired because of the "missing money" problem. Additional RMR contracts would seem likely, and this is reflected in the substantial increase in the number of RMR requests submitted by generators in recent months.[63] Most of the requests have not yet been decided by FERC. If LICAP and the new demand curve were delayed, it seems likely that more of these requests would be made and approved than would occur once LICAP is implemented. In that event, RMR costs would be allocated to LSEs in the local load zone.

The increased costs attributable to LICAP and the sloping demand curve can also be seen as a transition problem, not a long-term effect. That is, the increased costs reflect a short-run transition from a vertical to a sloped demand curve, but in the long run (a period long enough to allow new investments to occur under either approach), there is no obvious reason to believe that the total cost of capacity supported and encouraged under the sloped curve is greater than the total cost of capacity that would be supported and encouraged in response to the current vertical curve. Indeed, to the extent that the sloped curve reduces investment risks by reducing the volatility and unpredictability of capacity prices associated with a vertical curve (assuming both curves are set to achieve the same equilibrium level of capacity), the ISO can argue that total costs will be lower under its approach than would be the case if the vertical demand curve remained in place. There does not appear to be an empirical way to test these arguments.

[62] See, e.g., Opening Brief of the New England Conference of Public Utility Commissions (NECPUC Opening Brief); Letter from New England Congressional Delegation to FERC Chairman, July 5, 2005. ISO-NE originally requested a FERC decision on LICAP by mid September 2005, to allow it to implement ICAP by early 2006. However, in response to substantial opposition from New England regulators and public officials, FERC granted a request for oral arguments, now scheduled for September 20, 2005. *Order Granting Oral Argument and Delaying Implementation of Locational Installed Capacity Mechanism* in FERC Docket ER03-563-030 (August 10, 2005 Order). FERC did not set a date for a decision, and this required the ISO to abandon its plans to implement LICAP prior to the summer of 2006. As of this writing, no new date has been set.

[63] LaPlante Rebuttal 4-5, 49, 70, 72. LaPlante suggested that as many as 10,000 MW of capacity might eventually apply for RMR treatment in the absence of the ISO proposal.

Who Speaks for Loads?

The ISO's interpretation and specification of a "regional reliability standard" has created further opposition to the sloped demand curve approach among New England state regulators, officials and parties representing loads. Their principal argument is that the ISO has created a new regional reliability standard by specifying that the region should not fall below OC more than 17 percent of the time. This new standard, they argue, would impose substantial additional costs on New England consumers and would "institutionalize excess capacity that has existed in New England over the past 21 years."[64] These parties appear to accept without question that the regional reliability criterion (OC) is and should be based on the long accepted 1-day in 10-years LOLE criterion. However, they do not support the ISO's further interpretation that the region should achieve that criterion by not falling below it more often than the ISO claims occurred in the past. During the hearings, state regulators and other parties opposing the ISO proposal criticized this interpretation of the "regional reliability standard" on technical grounds, claiming: (1) the historic data is not a sound basis for predicting future variability in capacity relative to OC, because the proposed market will work differently[65] from the prior regulatory regime; (2) even if historic data is relevant, the ISO's choice of data was faulty. In addition, opponents made important policy arguments against the ISO proposal: (1) the states, not the ISO, should have the responsibility for setting the reliability standard and (2), the states have never approved the ISO's interpretation of the regional reliability standard.

These latter arguments raise important issues: In the absence of direct indications from consumers about their willingness to pay to avoid involuntary curtailments, who speaks for consumers? If the design and placement of the demand curve is to be done through administrative means, who has the responsibility to specify how much reliability consumers should be asked to pay for? If the point of the state opposition is that the ISO's demand curve will force consumers to pay for more capacity than consumers should be required to buy, then what level of capacity (how much reliability) are the state rate regulators willing to accept on behalf of consumers?

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[64] See, e.g., Initial Brief of the New England Conference of Public Utility Commissioners (NECPUC Brief); Testimony of Drs. Pechman and Bidwell on behalf of Connecticut DPUC and other Parties, 27, 35-36.

[65] State regulators collectively (as in the NECPUC Brief) took conflicting positions on how well the LICAP/demand curve approach would work. On the one hand, the regulators doubted that the approach would actually induce new investments and expressed concern that it would only provide "windfall profits" to existing plants. On the other hand, when arguing about the parameters of the demand curve, regulators and load parties consistently argued that the variability of capacity in the future under the ISO's curve would be significantly less that what the ISO observed historically. This would then translate to a smaller distribution, and hence smaller standard deviation – the distance between OC and C_{target}. In other words, less variability and a smaller standard deviation would allow the ISO to shift the entire curve to the left, reducing the capacity requirement and thus lowering total costs – the effect the States were hoping to achieve. Applying a smaller standard deviation to the placement of the demand curve would mean that significantly less capacity would be needed than in the past to meet the same average level of reliability. The States' argument thus implies that the ISO market will work quite well, not only in inducing new investment but also in keeping the level of investment fairly close to the desired reliability levels with less over- or under-building. None of the State or load parties has attempted to reconcile these conflicting positions.

Importantly, New England state regulators or public official did not squarely address these questions. Yet state regulatory silence on issues that appear to go directly to their authority to define just and reasonable retail rates may lead to an ironic result: If states within the region fail to specify the reliability standard in meaningful detail, and fail to take responsibility for the resulting costs and reliability levels, then the practical effect may be to leave the ISO proposal as a default, with the ultimate decision made and imposed by FERC.

Defining and Implementing Locational ICAP Markets

The original ISO-NE LICAP proposal would have created four LICAP zones, but in its June 2, 2004 Order, the FERC asked whether an additional zone would be appropriate for Southwest Connecticut. In a subsequent filing, ISO-NE concurred and asked for approval of this fifth zone, which FERC approved.[66] The resulting five zones under the current LICAP proposal are:

(1) Maine, which is recognized as a transmission constrained generation pocket,

(2) The region defined by Northeast Massachusetts (NEMA) and Boston, an area generally recognized as a transmission constrained load pocket,

(3) Connecticut (except for SW Conn.), into which there is limited transmission capacity from the rest of New England,

(4) Southwest Connecticut, into which serious transmission constraints limit the transfer of power even from the rest of Connecticut, and

(5) The rest of the ISO-NE footprint ("rest of pool").

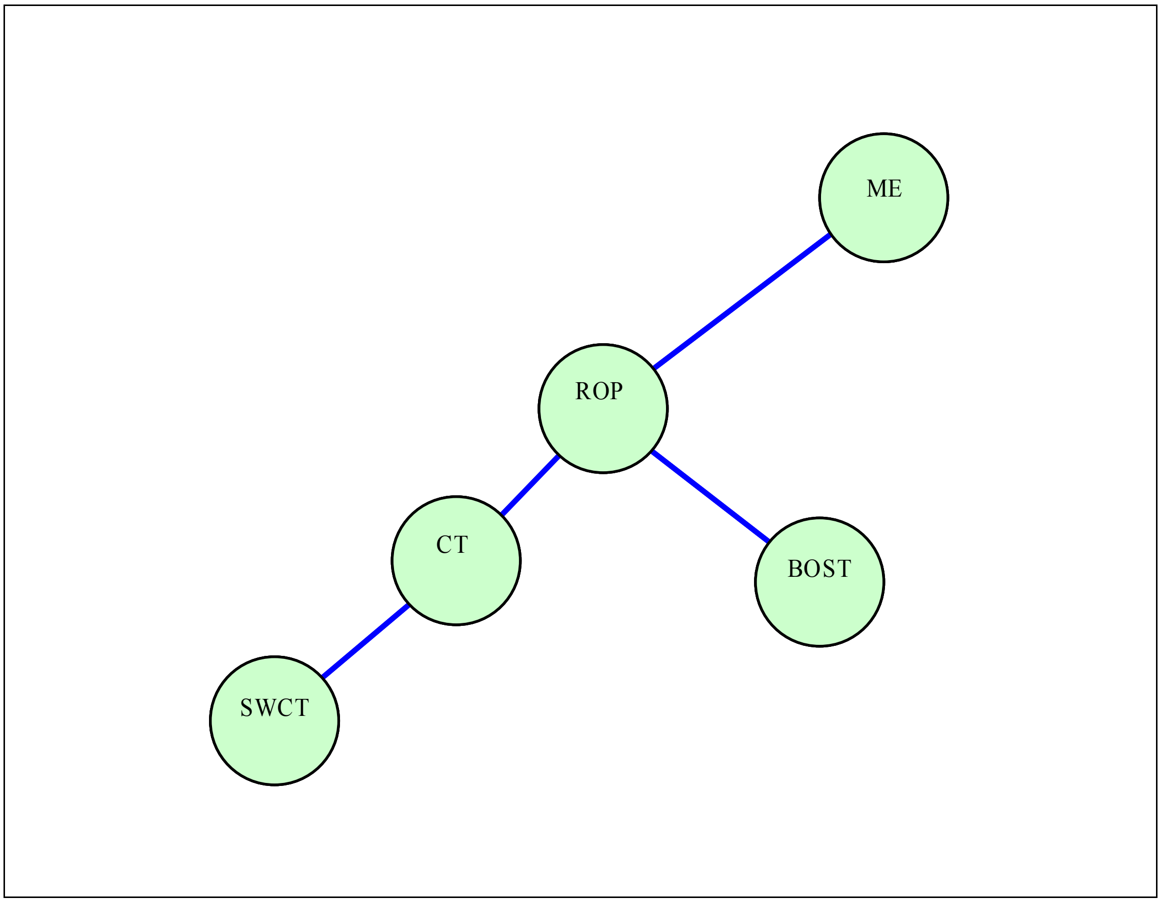
The New England LICAP zones continue the pattern observed in New York, in which the identified zones are amenable to a relatively simple cascading approach when defining local requirements and transfer rights. In New York, the major constraints move from "rest of state" to New York City to Long Island in a simple radial fashion. There has been no effort to further differentiate LICAP zones, such as by acknowledging transmission constraints within the New York City or Long Island zones that might further limit the ability of capacity in one part of the zone to meet the reliability requirements of another part of the same zone.

In the ISO-NE proposal, there are five zones proposed for New England instead of three (as in NY), but the zones reflect a view of the New England system in which flows from generators in Maine are limited into the rest of New England, and from there flows are limited into the NEMA/Boston and Connecticut regions and then into Southwest Connecticut. The zones thus line up in an essentially radial configuration that appears to avoid the need to examine simultaneous transfer limits into the same zone from multiple abutting zones. It is not clear whether this accurately reflects the actual grid configuration or is instead a deliberate design

[66] *Order on Compliance Filing* 109 FERC ¶ 61,156 (November 8, 2004 Compliance Filing Order)

constraint imposed in the hope of keeping market implementation easier. These questions are not addressed in the ISO proposal. The apparent configuration of the ISO-NE zones is shown in Figure 9.

Figure 9
Locational ICAP Regions and Transmission Interfaces



This figure, from Dave LaPlante's Direct Testimony of August 31, 2004, page 30, does not indicate whether the interfaces between zones have directional interface limits with different limits in each direction. The drawing indicates a radial system, but it does not describe how New England relates to New York or other systems.

When examining the effectiveness of a LICAP approach, an important question is whether a limited number of LICAP zones can effectively solve the "missing money" and "missing incentive" problems accurately enough to effectively reduce the need for RMR-type solutions. The energy markets settle each generator at its nodal LMP, and price mitigation rules may have different effects at different locations. The use of a few LICAP zones may only partly address the missing money problem, leaving some locations within a zone in which the combined compensation from the nodal energy market and the zonal LICAP market provides neither the right incentives for investments at those locations nor the right incentives for operational decisions that encourage availability.

As observed in *energy* markets (e.g., California) where settlements are done on a zonal basis, there can be constraints within each zone that would warrant different locational prices, hence the need for LMP. When that occurs, the use of zonal energy prices can create perverse incentives that are reflected in both investment and operational decisions inconsistent with the need for reliability. The same concerns would appear to apply if ICAP payments are based on large LICAP zones if the zones do not accurately reflect the actual constraints on the ability to move power from one region to another. This suggests that while LICAP may be an improvement over a regionally uniform ICAP payment regime, it may not eliminate the need for additional compensation schemes for selected generators at selected locations important for reliability. RMR-type contracts would likely still be needed at specific locations within a LICAP zone, and the extent of their use would depend in some part on how well the LICAP zones accurately reflect the actual constraints that limit the deliverability of power on the grid.

A further implication of the limits of the LICAP zonal approach is that the ISO may find it politically difficult to redraw zonal boundaries or create new LICAP zones if it finds that constraints within an existing zone are forcing too much reliance on RMR type solutions to compensate units needed for local reliability. In Connecticut, the ISO-NE has experienced considerable public opposition from many local officials and customer groups objecting to the creation of a separate Southwest Connecticut zone, and this in turn has helped undermine support for the overall LICAP proposal from state officials.

The judgments involved in setting and enforcing the transmission constraints applied in the reliability calculations can only approximate the limits imposed by the physical system used for actual operations. Constraints within the zones influence the calculation of the Capacity Transfer Limits between zones. Hence, it is not a straightforward matter to set the criteria and define the zones. The choices affect both reliability and the transfer of significant payments among the parties.

Transmission capacity

In the ISO-NE LICAP proposal, transmission capacity is explicitly defined as the difference in the total capacity requirement for a LICAP Region (zone) and the amount of that requirement that must be satisfied by capacity resources located in that LICAP Region. Each year the ISO would determine a LICAP Region's requirements in proportion to that Region's share of the New England Control Area coincident peak from the previous year.[67]

For each LICAP Region, the ISO would conduct a reliability study to determine the portion of that Region's capacity requirement that must be provided from resources located within that Region. The Capacity Transfer Limit or CTL determined for each LICAP Region represents a

[67] Direct Testimony of Mark Karl at 4-5. See also Karl Rebuttal at 4-5.

constraint on the ability to import capacity to meet capacity requirement in the Region or Regions on the import side of that constraint.

The Capacity Transfer Limits determined by the ISO-NE allow for modeling nested LICAP Regions and export constrained LICAP regions. In particular, the New England LICAP market models Southwest Connecticut LICAP Region as import constrained within the Connecticut LICAP Region, which in turn is import constrained from the rest of the pool. It also models Maine as a LICAP Region that is export constrained from the rest of the pool.[68]

Transmission rights

The ISO-NE proposal would explicitly define transmission rights. For each LICAP interface the total quantity of available Capacity Transfer Rights (CTR) is equal to the Capacity Transfer Limit (CTL) for that interface. These rights are financial; they pay the holder the difference in Locational ICAP prices between the two LICAP Regions associated with CTR.[69]

All resources purchased in a LICAP Region are paid the local clearing price and all LSEs are charged the local clearing price for all capacity purchased on their behalf. This settlement creates an over-collection of revenues by the ISO-NE, since the LSEs in import constrained LICAP Regions are charged the local clearing price for both local and imported capacity, while only local capacity receives this price. The role of CTRs in the settlement process is to allocate the over-collection of revenue to market participants that use the interfaces.

The ISO-NE deferred to the Commission how best to allocate the CTRs. According to Mr. Karl, the ISO was willing to consider accommodating a preferential allocation of the ability to import into, and export from constrained LICAP Regions following requests from market participants. Such requests might be based on past interconnection status of individual resources.[70] For example, in its original March 1, 2004 filing, the ISO suggested that CTRs on the Maine export constraint could be allocated to generators in Maine, allowing them to receive the price in import constrained LICAP Regions for capacity they provide in Maine that is exported to constrained LICAP Regions. In his later direct testimony, Mr. Karl suggested allocating CTRs associated with each constraint proportionally to all market participants serving the load on the import side of the constraint, reasoning that these are the entities that "ultimately pay the costs of the transmission system."[71]

The ISO-NE proposal to allocate the CTRs over each import and export constraint proportionally to the load served behind that constraint could be applied to the case of nested LICAP Regions. In particular, the example Mr. Karl provides in his direct testimony suggests that an LSE serving load in Southwest Connecticut would receive a share of the CTRs over the SWCT import constraint proportional to its load served within the SWCT LICAP Region. It would also receive

[68] Mark Karl Direct at 5.

[69] Mark Karl Direct at 3.

[70] Id. at 13.

[71] Id. at 26.

a share of CTRs over the Connecticut import constraint proportional to its load served within Connecticut LICAP Region. Finally, this LSE would receive a share of the CTRs over the Maine export constraint proportional to its load served on the import side of that constraint. Table 1 shows the example offered by Mr. Karl of distribution of CTRs across LSEs serving load within LICAP Regions of the ISO-NE.

Table 1: CTR allocation to LSEs in Locational ICAP Regions

	Percentage of CTRs allocated				
	Total Locational ICAP Obligation (MW)	SWCT CTRs	CT CTRs	NEMA CTRs	Maine CTRs
SWCT	4108	100.00%	51.78%		15.14%
Northern CT	3826		48.22%		14.10%
NEMA/Boston	5806			100.00%	21.40%
Rest of Pool	13394				49.36%
Maine	2232				
Total	29366	100.00%	100.00%	100.00%	100.00%

Source: Direct Testimony of Mark Karl at 22.

Using a Reserve Shortage Hour Availability Metric

The ISO-NE describes its proposal to use a reserve shortage hour metric to replace the current UCAP availability mechanism as an essential component of the overall proposal. Steve Stoft testified that he could not support the LICAP proposal if it did not include the reserve shortage hour metric.[72] While this feature of the proposal has strong support from most if not all of the state regulators and parties representing loads, it faces almost universal opposition from generators. In her Initial Decision (ID) issued in the LICAP proceeding on June 15, 2005, the ALR *rejected* the reserve shortage hours metric, finding that it was not sufficiently developed by the ISO and expressing concerns that it was not consistent with the availability metric (UCAP) used by PJM or New York.

Recall that a central purpose of the reserve shortage hour proposal is to ensure that generators that receive capacity payments are actually available to provide energy and/or operating reserves in those hours in which the system is most stressed and capacity is most valuable. Making ICAP payments depend on availability during these stressed hours was intended first to overcome two concerns with the UCAP approach: (1) the reserve shortage hour approach replaces the UCAP system that measured availability on an average basis, which ignores the fact that capacity has more value to the system in shortage hours than in non-shortage hours, and (2) it substantially reduces the degree to which a unit's score for availability depends on self reporting. It may also eliminate the need for a separate set of administrative penalties for non-performance when generators fail to meet their ICAP obligations.

The reserve shortage hour approach is intended to reward generators that contribute to reliability when capacity is most valuable, and avoids making (or reduces) capacity payments to generators that do not contribute to reliability when their capacity is most needed. This aspect of the proposal is particularly important to loads, who are concerned about the prospects of making higher capacity payments (during a transition or surplus condition) under the downward sloping demand curve than under the current system. From their perspective, if they have to pay more for capacity (in the short run), they want to make sure they are getting the reliability they are presumably paying for.

For the ISO, moreover, there was a second and equally important reason to change to a reserve shortage hour approach. The ISO-NE had experienced periods of reserve shortages and come close to rotating blackouts on past occasions, most recently during a previous winter. During that winter, some generators declared themselves unavailable for economic reasons when the region experienced a severe cold snap and associated price spikes and near shortages in the natural gas market. Some generators sold their gas back to the market, where its value was presumably higher than their own use.[73] One of the lessons that could be drawn from this

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[72] Stoft Rebuttal at 2.

[73] *Final Report on Electricity Supply Conditions in New England During the January 14-16, 2004 "Cold Snap"* P. 72. Published by ISO New England Inc. Market Monitoring Department. October 12, 2004. Available at http://www.iso-ne.com/pubs/spcl_rpts/2004/cld_snp_rpt/1_Final_Report_On_January_2004_Cold_Snap.pdf

experience was that generators were unlikely to take a variety of steps necessary to ensure electric generation availability, given the incentives provided by the UCAP approach. Yet it was unclear which steps generators should have taken: Should they have bought sufficient gas in advance? Should they have maintained gas storage? Should they have invested in dual-fuel capabilities? And should the ISO define these steps and mandate them as a prerequisite for meeting ICAP eligibility, or should the ISO change the incentives to reward those units that were actually available, and let the market sort out which of these actions made the most sense? ISO-NE chose the latter approach – change the incentives – in the belief that the market would do a better job in sorting out the right mix of investment and operating practices.

The ISO-NE's market incentive approach became an explicit ISO goal in the LICAP proceedings. The ISO-NE witness, Dr. Stoft, argued that the overall design of the LICAP markets was guided by the desire to mimic, wherever possible, the market incentives that would be provided by an "energy-only" market structure. Stoft reasoned that under an energy-only market structure (without explicit price caps and no ICAP markets or payments), generators would respond appropriately to the market price incentives of the uncapped energy market. They would decide which investments and operational practices would be worth pursuing to ensure that they received high energy prices when near shortages occurred and prices were highest. During periods of reserve shortages, energy and operating reserve prices would rise toward shortage-cost levels, and it would be these hours in which generators could expect to recover a large portion of their fixed costs and expected profits, *but in an energy-only market, only generators who were operating (or providing operating reserves) during those hours would actually receive these prices*. It followed that if the ICAP markets were to provide the missing money resulting from energy market price caps, then to mimic the incentives of the energy-only market, the payments for ICAP should be made for essentially the same performance that would have earned the shortage-cost energy prices in the energy-only markets. ICAP payments should therefore be made to generators that provided energy and/or operating reserves during reserve shortage hours (which would presumably be about the same hours in which energy price caps would likely be triggered); and conversely, generators that failed to be available – failed to provide energy and/or operating reserves – during these critical hours should not receive ICAP payments (or should have their levelized ICAP payments correspondingly reduced), because they would not have received the high energy prices in the energy-only market.

Most of the New England generator's arguments against the reserve shortage hour metric were based on the idea that it would be unfair to financially penalize a generator if it were unavailable for reasons outside the generator's control.[74] In addition, generators claimed that the approach was untried and inconsistent with the metric used in New York, and if different from New York, the New England approach might pose a barrier for inter-regional ICAP trading.[75] The ISO responded to these concerns, arguing that in an energy-only market, generators might also be unavailable for a variety of reasons but, according to the ISO, no one would argue that in an energy-only market generators should be paid for energy or operating reserves they did not

[74] *Joint Initial Brief on Availability Criteria of the Capacity Suppliers and Con Edison Energy*. FERC Docket ER03-563-030. April 15, 2005 (Capacity Suppliers) at 17.

[75] Initial Decision at 207.

provide.[76] Otherwise, the ISO argued, the approach would resemble a cost-of-service approach and not a market-based approach. The ISO also offered to continue calculating the UCAP value for units based in New England that sought to sell capacity to New York (as well calculating the availability rating based on reserve shortage hours), thus reducing concerns about inter-regional trading barriers.[77] In her ID, however, the ALJ concluded that while the approach was "promising," the Commission should reject the ISO-NE proposal at this time because of its novelty and the fact the ISO had not addressed every possible concern offered by the generators.[78]

ICAP Payments Under the Reserve Shortage Hour Metric

If, notwithstanding the ID, the Commission approves the reserve shortage hour metric, the proposal would affect how generators are paid for ICAP. The ISO proposes that ICAP payments paid to a generator each month be adjusted by an availability factor (A_g) that reflects that unit's availability during all previous reserve shortage hours during the prior month.

If the new metric is implemented, each generator will begin with its then current UCAP rating. Thereafter, each generator's availability factor will be adjusted after each shortage hour to reflect whether or not it was available during any shortage hour(s) during that month. The new data for each shortage hour is then blended with the previously determined availability factor to derive the new availability factor. After this adjustment process is made in sequence for each shortage hour, the resulting availability factor is used to determine payments in the next month's auction.

$$\text{New } A_g = (.95 * \text{Old } A_g) + (0.05 * A_{hg})$$

Where:
Old Ag = the availability factor for that unit from the last Ag calculation
Ahg = whether the unit was or was not available during the shortage hour since the last Ag calculation[79]

The resulting Ag at the end of the month is then applied for the next month's LICAP payment. Applying the formula, if there was a single shortage hour during the month, and the unit was available during that hour, the unit's availability factor would increase by 5 percent over the previous month; if the unit were not available during that shortage hour, the factor would decrease by 5 percent from the previous month. A separate adjustment would be made for each

[76] Stoft Rebuttal at 119:5-11.

[77] Mark Karl Rebuttal at 24.

[78] Initial Decision at 203-206.

[79] LaPlante Rebuttal at 86. The "measure" referred to here has not been fully defined by the ISO. In the simplest terms, it appears that the measure would be either "was available = 1.0" or "wasn't available = 0.0". It is not clear whether a unit that was partially available (for part of an hour or for partial capacity) would receive a partial or proportional score.

shortage hour during the month, in sequence. Thus, if there were two shortage hours during the month, the availability factor coming into the month would first be adjusted for the first hour, and then the resulting availability factor would be adjusted for the second hour. If no shortage hours occurred during the prior month, there would be no adjustment for the next month, and the availability factor from the previous month would carry over.[80]

During the LICAP hearings, generators pointed out that a unit starting with a relatively high factor, such as .90, would find that if they missed a single shortage hour and had their factor lowered by 5 percent (to .855), it would take many shortage hours without missing to make up for the effect of the one hour they missed; this might take many months if there were few or no shortage hours for several consecutive months, but the reduced payments would apply throughout that period. While this is mathematically correct, the ISO argued that this was reasonable because it reinforced the desired incentive for generators to take all steps necessary to ensure availability during shortage hours.[81]

The ISO describes its reserve shortage hour approach as "flat and simple," in contrast to an earlier version of a proposed availability metric.[82] The earlier version focused on "critical hours" rather than reserve shortage hours. The original concept was to have the ISO identify which hours were "critical" to reliability, and then assign a weight to each hour, depending on the value of capacity in each hour relative to how critical the hour was. Payment adjustments to generators would then depend on which critical hour they missed and the relative weight of that hour. Under this earlier proposal, there might be as many as 200 critical hours in a year.[83]

Generator parties noted that the ISO had not clarified the criteria either for defining critical hours in advance or assigning the weights for each critical hour. Rather than refine this approach further for the hearings, in its rebuttal testimony, the ISO replaced the critical hours approach with its reserve shortage hour proposal. The "flat and simple" reserve shortage hours approach treats all shortage hours the same: that is, capacity is valued the same in an hour whether the operating reserves fall to 5 percent or 3 percent.[84]

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[80] Initial Decision at 87.

[81] *Errata to Reply Brief of ISO New England, Inc.* in FERC Docket ER03-563-030. April 27, 2005. (ISO Reply Brief) at 83.

[82] LaPlante Rebuttal at 83.

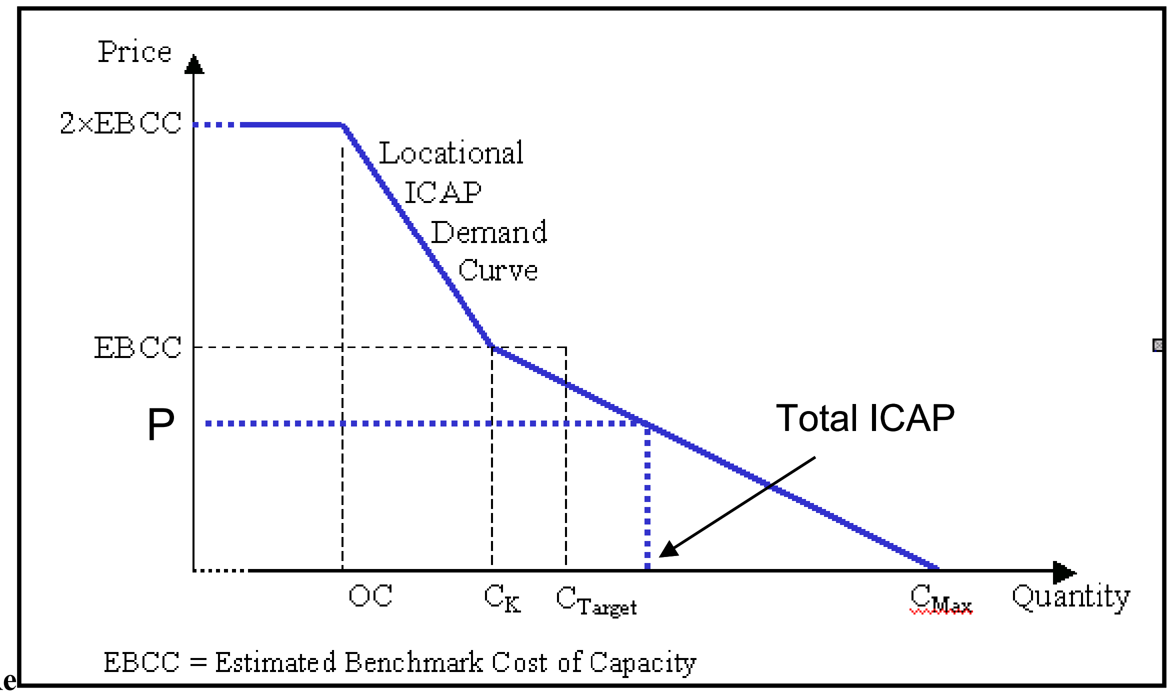
[83] On the original "critical hours" proposal, see Stoft Direct at 24-27; on the reasons for changing to the "flat and simple" shortage hours approach, see LaPlante Rebuttal at 14-15. For example, generators noted that the critical hours and their weighting would not be known in advance; some critical hours might be similar to non-critical hours; generators would find it hard to guess which hours would be critical and might be induced to self schedule their units uneconomically, thus distorting the energy market. Initial Decision at 78-79.

[84] Compare with the NY ISO approach of increasing operating reserve prices depending on how far the ISO falls below the operating reserve target. See, Harvey, "ICAP Systems" at pages 55-57.

Market Power Mitigation and the LICAP Payment Approach

The principal market power mitigation feature proposed by the ISO-NE would count all capacity in the region as "supply" and use that total number to derive the price for ICAP in the monthly auction. The price would thus be taken directly from the downward sloping demand curve and would not be affected by whether or not generators submitted offers for their capacity or by the prices offered by those generators. The intent was to make it difficult for generators to succeed in either physical withholding or economic withholding to raise prices.[85] The basic approach is shown in Figure 10.

Figure 10
ICAP Prices Set by Demand Curve



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For puposes of setting the monthly ICAP price, the ISO proposal would count capacity even if it were mothballed. The ISO reasoned that even though a plant might be mothballed in the short run, the capacity could within a reasonable period (a month or so) be reactivated and made available in the event that the owner could foresee monthly capacity prices rising to levels that would warrant reactivation. Since the demand curve mechanism was designed to affect long-run investment in new capacity or long-run decisions to retire capacity, the ISO argued that until a unit was retired,[86] it could be made available to meet New England long run reliability

[85] *Prepared Supplemental Direct Testimony of Steven E. Stoft on Behalf of ISO New England Inc,,* ERC Docket ER03-563-030, November 4, 2004 (Stoft Supplemental) at 4-6.

[86] If a unit's retirement were announced, that unit would no longer be counted toward setting the LICAP price. If the owner decided to bring such a unit back in to operation, it would not be allowed to receive capacity payments for three years. LaPlante Rebuttal at 108.

targets. Until its announced retirement, therefore, the unit would be counted towards the total capacity available to the region for purposes of setting the monthly ICAP price. However, if a unit remained mothballed for three years, it would no longer be counted. [87]

How are Exports and Imports Counted?

The total supply of installed capacity can be affected by net imports and exports. With respect to imports, ISO-NE proposed to count their capacity when defining the price. At the same time, the ISO-NE proposed to subtract exports from New England (e.g., capacity sales to New York) in defining the total capacity that defines price. With respect to exports, however, the ISO acknowledged that owners of substantial generation might be tempted to export some of theircapacity to New York when it was not economic to do so, which would have the effect of "withholding" capacity from the New England market and raising New England ICAP prices that would be paid to the owner's remaining capacity. To discourage this strategy, the ISO proposed to compare expected (or current) capacity prices in the two markets, with the comparison based on UCAP values. If the ISO determined that a sale of capacity into New York was uneconomic (i.e., had a significant negative margin beyond some safe harbor dead band) the ISO would reduce the New England capacity price that applied to any remaining New England capacity owned by *that* capacity owner, but not to the capacity owned all other capacity owners. In that way, the owner that was presumed to be withholding capacity via an uneconomic export would not receive the profits from the increased New England prices caused by the export. The ISO assumed this would be enough to discourage such withholding.[88]

LICAP Payment Reduction for Peak Energy Rentals (PER)

ICAP payments to generators are determined by the ISO-NE demand curve for any given level of total (operating and mothballed) capacity. The ICAP payments for each operating unit whose capacity cleared the monthly auction are then adjusted by subtracting the calculated energy profits –Peak Energy Rentals – that would have been earned by the hypothetical benchmark generator in the ISO's real-time energy markets. Payments for each generator are then further adjusted by that unit's availability factor (Ag). The payment calculation can be illustrated as:

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[87] LaPlante Rebuttal, at 16; Stoft Rebuttal at 141.

[88] Mark Karl Rebuttal at 74-75. For exports from New England to New York, the New England generator is provided with a UCAP rating, which is utilized by New York in its capacity market The UCAP rating is multiplied by the clearing price in the New York zone in which the export is to be delivered to determine gross revenue from the transaction. Net revenue is calculated as gross revenue less the internal New England LICAP congestion charge, equal to the ICAP value of the transaction multiplied by any positive price differential between the New England source and sink zones. The net revenue is compared to the calculated value of the transaction in New England. This value is calculated as the ICAP value of the transaction multiplied by the previous month's LICAP price for the zone in which the generator is located, less the calculated energy market revenue of the applicable benchmark generator. The result is multiplied by the shortage-hour availability statistic to obtain the transaction's value in New England. If the net revenue from New York is greater than or equal to the calculated value in New England, the transaction is considered economic. If the transaction is uneconomic, it will not be denied, but the capacity will continue to count as available capacity in its original zone. Karl Rebuttal at 35-36.

$$\text{Payment} = MW_{ICAP} * Ag * (\text{LICAP price} - \text{PER})$$ [89]

Where,
Ag = the availability factor for that unit's capacity, for the auction month
LICAP price = that month's price of capacity from the LICAP zone's demand curve
PER = Peak energy rentals of the benchmark unit, averaged over the 12 previous months

Subtraction of the peak energy rentals is required to ensure that the total payments made to a generator similar to the hypothetical generator would not pay twice for the profits the unit could have made in the energy markets. This is consistent with the underlying concept that the ICAP payment is intended to provide the "missing money" resulting from the imposition of caps or other limits on the energy market prices.[90]

The PER is calculated based on actual energy prices in the ISO's real-time spot market.[91] The ISO argued that this would provide a better representation of the likely profits from a peaking unit like the benchmark unit than reliance on day-ahead prices. The PER reduction for any month would be the rolling average of the calculated PER for the previous 12 months (N-13 through N-2) and would be determined before each monthly auction. Generators would thus know in advance of the auction what the PER adjustment would be for that auction month.[92]

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[89] LaPlante Rebuttal at 85.

[90] Initial Brief of ISO New England at 47. There is an unresolved issue about whether the PER reduction approach should also apply to profits that the benchmark unit might earn in markets other than energy. The ISO did not make a proposal on this issue, but load parties argued that the PER rationale should apply to revenues for all markets in which the generators are compensated. The ID agreed in principle, but also agreed with the ISO that there was insufficient evidence on what these other markets might be to include a provision to address their rentals at this time. Initial Decision at 156

[91] In the ISO-NE approach, the rentals are determined by the difference between the actual spot prices in the real-time energy market and a hypothetical competitive price, defined as the variable costs of the benchmark unit. The ISO uses a frame gas-turbine generator as the benchmark unit, with an assumed availability factor or 90 percent, which Stoft notes has the highest variable costs of any economically efficient unit. As a result, Stoft says, inframarginal rentals are the smallest and most accurately estimated in dollar terms, thus insuring the most accurate LICAP payments. For fuel prices, the ISO proposes to use a volume-weighted average of three city-gate prices. These are day-ahead prices, which the ISO recognizes as not ideal. However, the ISO would also adjust the benchmark variable cost estimates by a bias factor, which is the result of comparing the model-predicted PER for actual units in the market to actual revenue derived by those units in the market. Thus, if the model were found to over predict PER by 20 percent, then the bias factor would be 0.8333 (the result of 1/1.20). The bias factor is meant to correct for any systemic bias in the calculation of PER. Some of these details are still under development. E-mail from Mark Karl. The profits earned by the benchmark unit would also vary from zone to zone, based in locational energy prices applicable to the benchmark unit. Stoft Direct at 11-12, 19-20.

[92] LaPlante Rebuttal at 84-85; Initial Brief, at 47-48.

Could The PER Reduction Result in Negative ICAP Payments?

During the hearings, parties noted that the PER reduction could be larger than the ICAP payment for some months, which would suggest a negative payment for capacity in that month. This issue arose primarily because under its original proposal, the ISO would have calculated the PER for each month and applied that month's PER to adjust that month's LICAP payments. This meant that the PER adjustment might be somewhat volatile, with peak unit profits higher in some months of high peak usage but minimal or zero in other months. During months with very high peak profits, the PER could be higher than the unadjusted monthly LICAP price. Initially, the ISO proposed a balancing account approach to avoid negative payments, but this approach was replaced.

In its Rebuttal testimony, the ISO changed its proposal so that PER would be calculated as the average of the previous 12 months, which would presumably flatten the PER adjustments (hence the terms "flat and simple" approach) and reduce the likelihood that the PER in any month would exceed the LICAP prices. With this change, the ISO proposal does not allow for negative payments. If the PER adjustment is greater than the LICAP price, the payment is zero.[93]

Does the PER Reduction Mitigate Market Power in the Spot Energy Market?

Earlier ISO descriptions of the PER reduction suggested that it might also serve to mitigate prices in the *energy* markets. The argument at the time was that if generators knew that their ICAP payments would be reduced by profits achieved in the energy market by the hypothetical peaking unit, there would be a reduced incentive to drive up prices in the energy market, since this would raise the PER calculated for the benchmark unit, which would then be deducted from ICAP payments.[94]

However, it appears that much of the strength of this argument rested on the original proposal to calculate the PER adjustment monthly, after the fact, and then make that month's PER adjustment to that month's LICAP payment. Thus, there would be a reasonably direct correlation between higher prices from market power in any given month and PER adjustments in that month.[95] When the ISO changed its PER approach to calculate the average PER for the previous 12 months, this direct month-to-month connection was broken. Nevertheless, the ISO-NE still claims that the PER adjustment will significantly discourage the exercise of market

[93] LaPlante Rebuttal at 84-85. However, the ALJ concluded that a potential concern for negative payments still remained. The Initial Decision directs the ISO-NE to propose a solution to this possibility. Initial Decision at 156.

[94] Stoft Direct at 19, 22.

[95] A much stronger correlation would occur if the PER were calculated for each shortage hour and applied against capacity payments made on an hourly basis. In that event, the Benchmark generator could not keep the rents it earned, because they would be subtracted from the LICAP payments, so market power would be fully mitigated. When the PER is calculated monthly, and then averaged over 12 preceding months before defining the amount to be subtracted from the LICAP payment, any mitigating effect with respect to market power would appear to be greatly attenuated.

power in the energy spot markets, because the PER deduction, while not immediate, is spread out over the year. However, it notes that, in theory, a generator could exercise market power in the energy market and then "leave the market for the next year, either to export or to retire," although this might rarely occur.[96]

Is the ISO-NE LICAP Proposal a "Market?"

The support or opposition to the ISO-NE pricing mechanism mirrors that found for the proposal to use reserve shortage hours as the availability metric: load parties and state regulators strongly support the pricing mechanism approach to market power; generators strongly oppose it. Most generators argued that mothballed or "delisted" units should not be counted towards the total. They also argued that the ICAP auction price should be set by the intersection of the demand curve and a supply curve defined by the ICAP suppliers' price offers. Otherwise, they argued, the pricing mechanism was not a "market" but was merely an administrative mechanism to determine a capacity payment.

These concerns echo other comments that suggest that the overall demand curve approach is administrative and therefore not a market-based approach, as required by FERC. These comments appear to be half correct. On the one hand, there is no dispute that the demand curve is entirely derived through an administrative process. That is the consequence of the threshold decision not to rely on consumer responses to high prices in an uncapped energy-only market structure. Given this decision, all aspects of the "demand curve" must be administratively derived. However, it does not follow that supply-side responses to the administrative demand curve are not "market based." Stoft argued that even if the demand curve is administrative, and it defines prices without regard to supply offer prices, the supply side is still left free to decide how it will respond to those prices defined by the demand curve. Investors can invest to build new or sustain existing capacity or not; they can decide to retire existing plant or not, and they can decide where and how to allocate their investment, maintenance and operational dollars in response to the price incentives arising from the demand curve payments and the availability metric. Indeed, in defining the reserve shortage hours availability metric, the ISO has chosen an approach that leaves these key decisions to the market, rather than trying to direct the market where to put its focus and money.

The ISO might therefore claim that its approach is at least "half a market." It uses administrative approaches where, as the ISO would claim, it was given no other choice, but it uses market-based approaches where that choice was available.

[96] LaPlante Rebuttal at 87-88.

PJM'S RELIABILITY PRICING MODEL (RPM)

PJM's Reliability Pricing Model, or RPM, has been under development for more than a year. The basic approach was summarized in a November 2004 "White Paper" prepared by PJM for stakeholder comment.[97] Since then, there have been numerous stakeholder forums sponsored by PJM to discuss the merits and refine the proposal, and interaction with the PJM Board, as well as a FERC-sponsored technical conference held on June 16, 2005. PJM and its Board have sought stakeholder support for its RPM proposal, but so far the proposal has failed to achieve even majority support from the PJM Members Committee.[98] Nevertheless, PJM filed its RPM proposal at FERC on August 31, 2005.[99]

PJM's Reliability Pricing Model contains several common elements with the New York markets and the ISO-NE proposal, plus additional elements that expand the scope, purpose and complexity of the RPM. The most notable difference is the PJM proposal to hold a resource adequacy auction four years prior to a delivery year (Base Auction), plus three other supplemental forward auctions between the Base Auction and the Delivery Year as the primary mechanisms to acquire adequate resources. In these forward auctions, new generation capacity would compete against existing capacity, while merchant transmission upgrades and demand-side proposals would also be allowed to compete. The major features of the PJM RPM proposal include:

1. *PJM would use forward auctions for capacity products to be delivered four years later; the four-year forward commitment period is intended to allow new entry and competition from transmission and/or demand response measures.*

2. *PJM would identify specific generator features that would be rewarded with higher prices in the LICAP auctions.*

3. *PJM's RPM structure would be locational, with two zones initially and more zones later.*

4. *PJM auctions would use downward sloping "variable resource requirement" (demand) curves.*

5. *Auctions prices would be determined from the intersection of supply and demand curves.*

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[97] PJM, *Whitepaper on Future PJM Capacity Adequacy Construct: The Reliability Pricing Model*, November 2004, available at http://www.pjm.com/committees/working-groups/pjmramwg/downloads/20050110-rpm-whitepaper-formatted.pdf

[98] See, Letter of Phil Harris to the PJM Members Committee and Stakeholders, March 22, 2005, available at http://www.pjm.com/committees/members/downloads/ltr-to-mc-stakeholders-replaces-311560.pdf.

An initial vote was held by the PJM Members Committee on January 26, 2005, and second vote held on March 17, 2005. In both cases, the proposal failed to gain the necessary (60 percent) support or even a majority. The matter was also considered by the PJM Board at its annual meeting on May 5, 2005.

[99] *PJM Interconnection LLC* in FERC Docket ER05-___-000 and EL05-___-000, August 31, 2005, (RPM Filing).

6. *PJM would mitigate market power through the use of bid mitigation and FERC orders to compel capacity offers*.

7. *PJM would retain the current approach to availability, which measures a unit's "unforced" capacity (UCAP based on average EFORd)*.

Forward Auctions and Delivery Years

In a significant departure from the approaches used in New York and New England, the PJM RPM auction approach would use staggered long-term forward auctions to acquire resources up to four (4) years in advance. Each year, a "Base Residual Auction," would acquire capacity resources that would not have to be available until the "Delivery Year," four years hence. With four years to meet the delivery obligation, proposed new resources could presumably participate in the Base Residual Auction against existing resources, providing some protection against the exercise of market power. A four-year lead-time might also allow some "merchant transmission proposals" and demand-side proposals to participate in the auction and compete directly with generation capacity proposals.[100]

Between the year of the Base Residual Auction and the Delivery Year, PJM would also hold three "incremental auctions." Two of these "incremental auctions," would be held 23 months and four months prior to the Delivery Year. These auctions would allow parties to substitute resources for resources that had been committed in the Base Residual Auction but whose delivery had become doubtful for any reasons, such as cancellations, delay, derating or other changes in UCAP ratings, or a decrease in the planned size of a new resource. The costs of any replacement resources committed in these two supplemental auctions would be assigned to the parties making the changes.[101]

A separate "incremental auction" would be held 13 months before the Delivery Year. Its sole purpose would be to allow additional resources to be committed, but only if the ISO determined that unexpected demand growth (100 MW or more, based on revised PJM forecasts 15 months prior to the Delivery Year) or other factors increased the need for capacity resources over the levels committed in the Base Residual Auction. The costs of any resources committed in this supplemental auction would be allocated to all loads.[102]

The sequence and timing of the Base Residual and three incremental auctions is shown in Figure 11.[103]

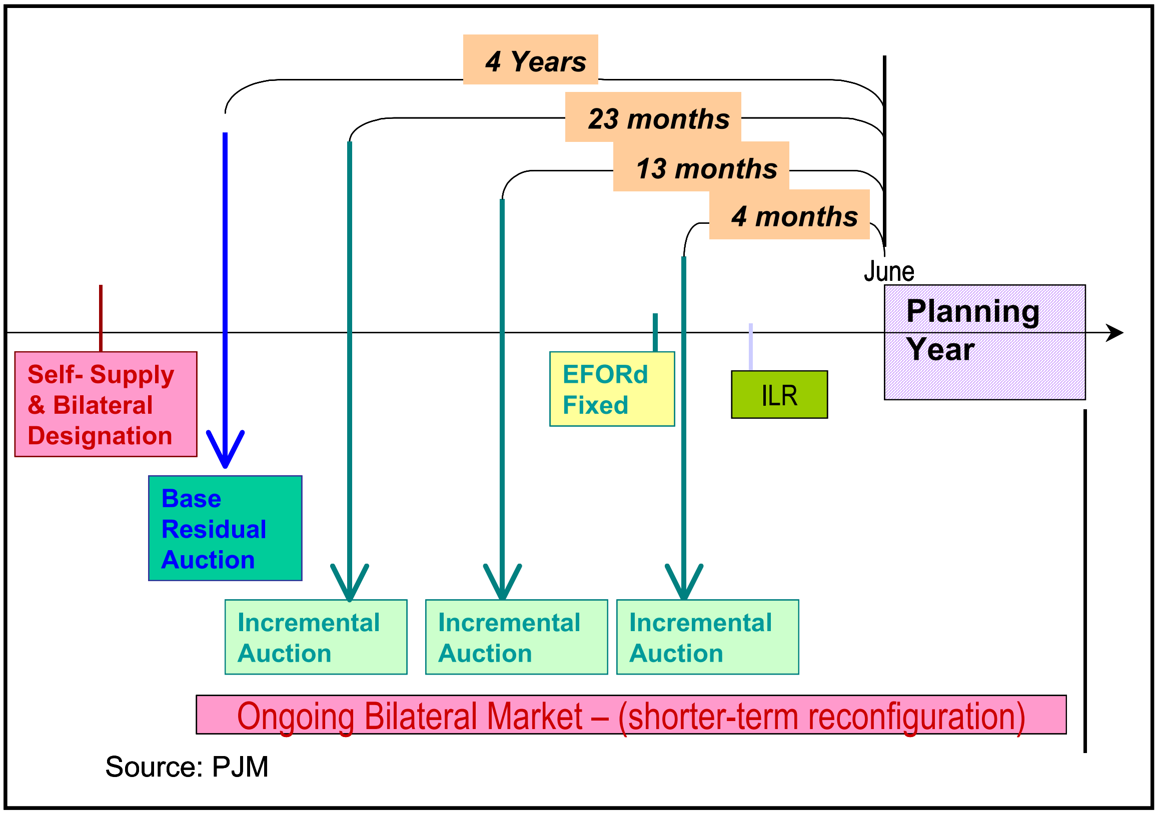
[100] PJM Filing at 52-53.

[101] PJM Filing at 54. All parties with replacements would pay the auction clearing price for replacements, rather than the costs of their specific replacement. Replacement costs for resources needed to relieve a locational constraint would be paid by the buyer whose resource was replaced. PJM Filing, Tab E, Affidavit of Andy Ott (Ott Affidavit) at 8, fn.7.

[102] PJM Filing at 54.

[103] PJM Filing at 52. Once RPM was initiated, there would be transitional measures to acquire resources if needed in years before the first Delivery Year.

Figure 11
Proposed Timing of RPM Auctions



The PJM proposal also provides an additional opportunity for demand-side resources to enter the market and receive capacity payments. In Figure 11, this is shown as "ILR" which stands for "Interruptible Load for Reliability." ILR providers could offer their resources as late as three months before the Delivery Year and still receive the same capacity prices paid to resources that participated in the Base Residual Auction.[104] The RPM filing notes that PJM will convert load response resources into a comparable measure of capacity so that they can be compared in the same auction as generation; however, the rules for making this conversion are not provided; they are to be developed in the future.

There is a similar requirement for comparing different types of generation on a comparable basis. According to Schedule 9 of the RPM Filing, "The rules and procedures shall recognize the difference in types of generating units and the relative ability of units to maintain output at stated capability over a specified period of time. Factors affecting such ability include, but are

[104] PJM Filing at 55. PJM would include a forecast of expected ILR resources in defining the remaining requirements for the Base Auctions.

not limited to, fuel availability, stream flow of hydro units, reservoir storage for hydro and pumped storage units, mechanical limitations, and system operating policies." However, these rules are not specified.

In addition to the Base Residual and incremental auctions, PJM proposes a "reliability backstop auction," in the event that the Base and incremental auctions are unable to procure adequate resources. The trigger for this backstop would be four consecutive years in which the Base auction failed to commit the desired level of resources. In that event, it appears PJM could, at any time, hold a backstop auction to acquire whatever resources it deemed necessary to meet reliability requirements; there would be long-run contracts between PJM and the resources.[105]

Settlements for capacity bought and sold in the auctions would not occur until the Delivery Year. That is, while loads would be obligated to pay for their respective shares of the resources acquired in the forward auctions up to four years in advance, their exact obligations would not be determined until the Delivery Year, and payments would not be due until the resources were actually delivered in the Delivery Year. Similarly, resources that cleared the forward auctions would not be paid until the Delivery Year. The structure thus depends on the regulatory certainty that payment obligations incurred in the auction years would be fully honored in each subsequent Delivery Year, for years in the future.

Promotion of Specific Generator Features

In its discussion of the problems it is experiencing with its current ICAP mechanism, PJM notes that between the announced retirements of capacity in Eastern PJM and the few recent capacity additions in its region, there has been a significant decline in generation with specific features that PJM requires to ensure reliable operations. In particular, PJM points out that many of the units planned for retirement were load-following units and/or units capable of starting quickly – that is, within 30 minutes -- and thus able to provide 30-minute operating reserves.[106] To address the decline in these flexible operating features, PJM proposes to identify these two operating capabilities as specific features that would be entitled to additional compensation in the Base Residual and incremental auctions.[107]

PJM proposes to identify, for each LDA/zone, a minimum level of each generation feature needed to reliably operate the system in that zone. The minimum level would then function as a constraint in the solution algorithm for each auction, so that if the constraint were binding, units that offered each of these features could submit higher offers to cover the costs of providing that feature and receive higher clearing prices for providing those features. If either constraint binds in the auction, the price for any resource with the relevant feature would clear at a higher level than necessary to allow the auction to commit the minimum amount of resources

[105] PJM Filing at 55; Ott Affidavit at 32.

[106] Ott Affidavit at 30.

[107] PJM Filing at 53.

with that feature needed for the region. Capacity resources that did not provide these features would receive lower clearing prices.[108]

The PJM RPM Structure Would Be Locational.

PJM proposes initially to create separate LICAP zones for two subregions of PJM. Each zone is called a "Local Deliverability Area," or LDA. One LDA would cover the pre-expansion MAAC area (sometimes called PJM Classic) plus the Allegheny system; the second LDA would cover the expanded areas of PJM (Commonwealth Edison, AEP, Dayton, Virginia/Dominion, and Duquesne systems). These two LDAs/zones would apply for the first year of RPM, proposed as June 1, 2006 through May 31, 2007. These areas are shown in Figure 12, at the end of this section.[109]

Additional LICAP LDA zones would be created in subsequent years, as shown in Figures 13 and 14. For example, by the second year, there would be two additional LDA zones for (1) the Eastern MAAC region of PJM, including the New Jersey, Eastern Pennsylvania and Delmarva peninsula regions, and (2) the Southwestern portion of MAAC, including Baltimore/Washington D.C. More LDA/zones could be created in later years, depending on the findings regarding transmission limits on deliverability, as determined in PJM's annual Regional Transmission Expansion Planning Process (RTEP). The last figure shows the various utility transmission systems that are now part of PJM and used to assess capacity deliverability in the current RTEP process. However, the number of LDAs would not be limited by the number of utility-owned systems but rather by the findings in PJM's RTEP process. In theory, any region or sub region within PJM could eventually become a separate Local Deliverability Area subject to different locational requirements and prices.[110]

PJM would retain its existing deliverability requirements and use the deliverability analysis in the RTEP to identify the need for and boundaries of new LDAs. Thus, each time the RTEP identified an a region of PJM with an existing or approaching deliverability constraint, the ensuing auction process would begin to acquire resources to meet the LDA reliability requirements through capacity additions and/or transmission upgrades to relieve the constraint.[111] It is worth noting that while the RPM structure would use forward auctions to procure resources four years in advance, the risks of long-run contracts would be affected by the fact that the number and boundaries of LDAs could change from year to year, and these could change dramatically during the first few years of RPM implementation, leaving parties exposed to risks of possible locational price differences but no clear way to hedge these risks.

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[108] PJM Filing at 58-59; Ott Affidavit at 31.

[109] All figures showing the possible LDA zones are taken from the PJM RMP Filing, Affidavit of Steve Herling (Herling Affidavit), Attachment 3.

[110] PJM Filing at 57-58; Herling Affidavit at 10-11.

[111] PJM Filing at 60; Herling Affidavit at 11.

PJM's deliverability analyses compare each region's Capacity Emergency Transfer Objective (CETO), which is "the amount of capacity that must be imported into an area during an emergency to ensure that the area can satisfy a transmission related loss of load expectation of only one day in 25 years," and the area's Capacity Emergency Transfer Limit (CETL) which is "the capability of the transmission system to transfer capacity into that area under those emergency conditions."[112] If this comparison shows that the CETO for an area exceeds the CETL for that area, the RTEP would specify transmission upgrades ("base upgrades") needed to increase the existing CETL up to the CETO (the area's import objective). This is the current process. What is new under RPM is that such a finding would also trigger the creation of an LDA, a zone for which capacity requirements and prices could differ in the next RPM auctions.[113] Note that the criteria for signaling the need for an upgrade and for triggering an LDA is a one-day in 25-years LOLE, which is significantly more stringent than the 1-day in 10-year LOLE criterion used to define PJM's UCAP reserve objective.

Each auction would take into account the resource offers in each LDA and the constraints (Transfer Limits) in delivering energy into each LDA, along with resource offers external to each LDA. When transmission constraints were binding in the forward auctions, such that less expensive resources could not be imported into an LDA, prices would differ between the LDAs. Generators with eligible capacity that cleared the market in the periodic auctions would receive the Final Capacity Prices in those auctions for their respective LDA. Each LSE would pay the Final Capacity Prices for its respective LDA times the its Daily Unforced Capacity Obligation. The amount paid by load is called the "Locational Reliability Charge."[114]

Because Capacity prices could vary between LDAs, parties that owned or contracted with capacity might face locational differences in the clearing price in the generator's LDA and the load's LDA. The difference between the generator's LDA price and the load LDA's price is called a "Locational Price Adder." Thus, a load that relied on generation located outside its own LDA would pay its own LDA prices plus the Locational Price Adder for the right to rely on that external resource to meet its share of the adequacy requirement. At the same time, loads would be allocated "Capacity Transfer Rights" (CTRs), which is somewhat analogous to the Financial Transmission Rights in the LMP-based energy markets. CTRs would entitle the loads to receive the Locational Price Adder for the amount of capacity resources equal to their allocated CTRs.[115]

Capacity Transfer Rights would be allocated pro rata to loads in each LDA. The CTR allocation to each Load Serving Entity would correspond to each LSE's pro rata share (given its capacity obligation, which is determined daily) of the capacity imported into its LDA. However, the total allocated in this manner would first be reduced by any specific allocations to entities that had paid for upgrades to increase the import capability into that LDA. These might include generators that had paid for upgrades as part of their interconnection agreements to ensure

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[112] Herling Affidavit at 5, 11.

[113] Id.

[114] PJM Filing at 53, 56, 59.

[115] PJM Filing at 59.

deliverability of their capacity. This implies that entities that built or paid for new upgrades in the future would also receive a corresponding allocation of CTRs to reflect the incremental expansion in the CETL into a given LDA.[116]

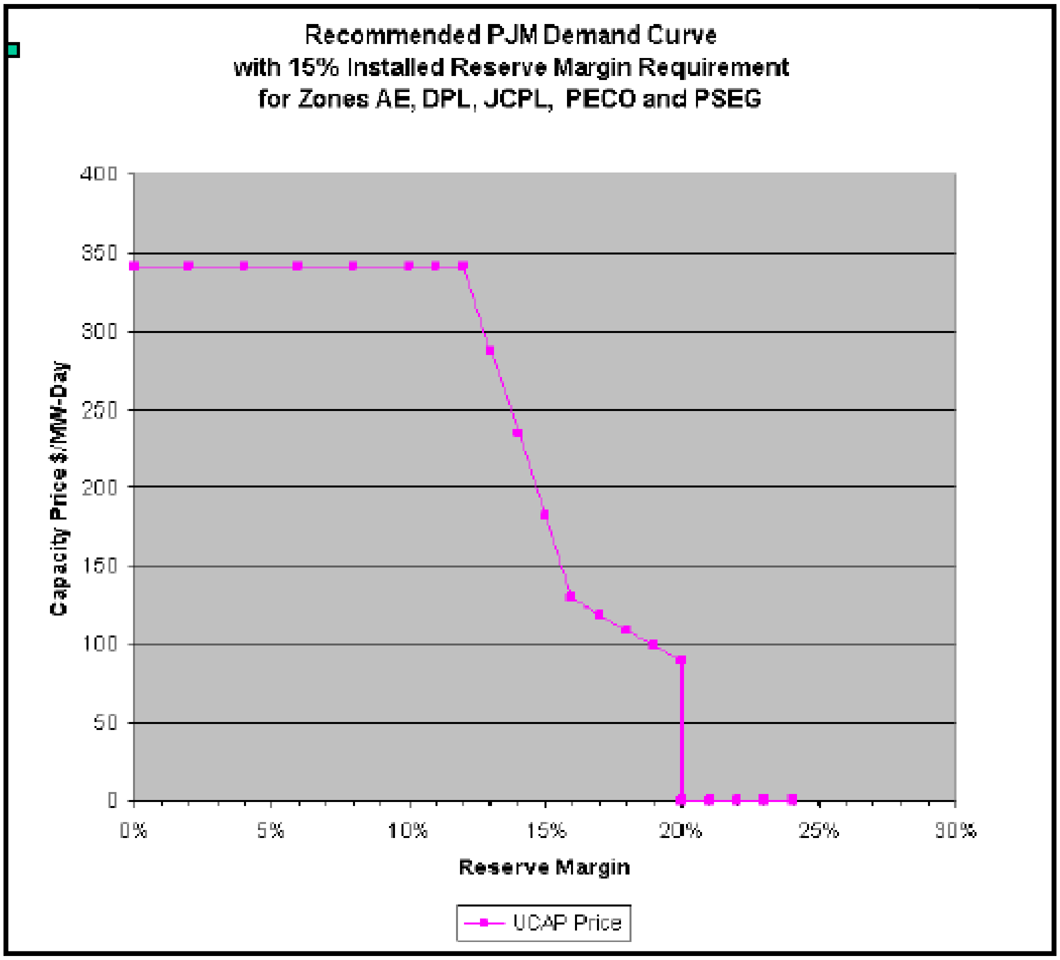
It is unclear from the RPM filing how the possibility of multiple LDAs beyond the initial two would affect how locational requirements in each LDA were set, how the CTRs would be defined and how they might function. The basic approach can be understood if applied to a relatively simple radial configuration with no network effects. However, it is not clear how the system could work in a more complex network in which simultaneous transfer limits would vary depending on the transfers from one LDA versus a second LDA into a third LDA, or where one LDA might be nested inside another LDA. The initial filing does not fully address this potential complexity, and this is a topic for further inquiry. However, this concern would likely not arise in the initial year or two of the PJM mechanism, because of the limited number of zones involved and their apparent radial connection.

PJM's RPM Uses a Downward Sloping Variable Resource Requirement Curve.

PJM describes its "demand" curve as a "variable resource requirement" (VRR) curve. These terms appear to acknowledge that this is not technically a "demand curve" in the classic economic sense. Instead, it is a curve designed to meet a reliability standard – a reserve margin consistent with the 1-day in 10-year LOLE criterion set by NERC (North American Electric Reliability Council) – while allowing the auction price of resources to vary with the level of resources offered relative to that standard. The design of the PJM VRR curve reflects the investment requirements of capacity resources at the target level of reserves. This is essentially what the New York and ISO-NE "demand" curves are trying to do. A generic version of the PJM proposed VRR curve for one region is shown in Figure 15.

[116] Herling Affidavit at 13.

Figure 15
Proposed PJM Demand Curve



PJM's propose VRR curve reflects the same basic concepts used to design the downward sloping curves in New York and New England.

1. The PJM curve centers on the conjunction of the breakeven point for recovering fixed costs for the benchmark unit at the target level of reserves *plus one percent*. The target level is set at 15 percent reserves above the expected peak demand, reflecting (approximately) a 1-day in 10-year LOLE for the PJM region as a whole.[117] The breakeven point is at the cost of new entry (called "CONE" in PJM) for the benchmark unit (PJM calls this the "Reference" plant) *net* of any contribution to fixed cost earned by the Reference unit from PJM energy markets and ancillary service payments.[118] (This is

[117] It appears that PJM would not calculate a separate reserve margin corresponding to 1-day-in 10-year LOLE for each LDA. The same 15 percent margin would be used for all areas.

[118] PJM has markets for regulation but not other operating reserves. However, generators are paid "make whole payments" for net costs of commitment or providing reserves, such as start-up and minimum generation costs, that are not recovered through the energy markets when the units are dispatched. In the calculation of net CONE, PJM

similar to the approach used in New York, but not in ISO-NE, where net revenues from the energy markets are not netted from the cost of energy or used to design the curve but are instead subtracted later, from the LICAP payments.) As in the NY and ISO-NE approaches, the benchmark/Reference unit is a frame combustion turbine (CT).

2. The curve has a zero crossing point, at 20 percent reserves, which is five percent higher reserves than the target level. Note, however, that the curve is truncated on the right side to force a zero crossing point at 20 percent reserves, rather than extending the curve out to the left (e.g., to 25 percent reserves or more, as originally proposed in the November 2004 *White Paper*). PJM made this change in response to comments from state regulators, who argued against making capacity payments when capacity levels went significantly beyond the target.[119]

3. There is a capacity price cap, set at two times the net cost of new entry for the Reference unit.

4. As in New England, the PJM curve also has a "kink," which allows a steeper slope for the left side of the curve (when reserves fall below the target) and a shallower slope for the right side of the curve (when reserves exceed the target level, until the curve meets the capacity level for zero price. In the PJM VRR curve, the kink occurs at the point corresponding to one percent above the 15 percent reserve target (i.e. at 16 percent reserves) and the net CONE. The choice of this parameter is discussed further below.

5. In the PJM approach, there is no attempt to determine or replicate historic capacity/reserve levels. Recall that in the ISO-NE proposed curve, the designer's intent is to encourage a level of capacity that does not fall below the reliability criterion of 1-day in 10-years LOLE more than 17 percent of the time, to reflect the ISO's view of historic practice in New England.

6. As in New York and New England, each LDA in PJM would have a slightly different demand curve, reflecting the different net cost of new entry for the benchmark/Reference unit in each zone. PJM proposes to reexamine the parameters of its proposed curve(s) "at least every three years."[120]

In selecting the parameters of its proposed curve, PJM undertook economic analyses of the likely investment responses to five alternative VRR curves using different parameters. One alternative VRR curve attempted to define the curve based on an assumed value of lost load (VOLL-Based Curve). A second alternative was the original curve proposed in the November

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includes a fixed contribution for ancillary services, set at $2,254 per MW-year, while noting that the Reference unit, a CT, is not likely to be providing most types of ancillary services. PJM Filing, Affidavit of Joe Bowring (Bowring Affidavit) at 6.

[119] PJM Filing at 53.

[120] Ott Affidavit at 23.

2004 White Paper. The third, or base curve plus two additional curves shifted 1 percent and 5 percent, respectively, to the right of the base curve were also considered.[121]

PJM describes the base curve (curve #3) as follows:

"A downward sloping demand curve with four segments: (a) a horizontal segment with an ICAP price equal to two times the fixed costs of a turbine if the reserves are less than 96% of the target reserves, minus the average [energy and ancillary services] gross margin, divided by one minus the forced outage rate: (b) another horizontal segment with a zero price if the installed capacity exceeds the target installed reserve margin of 15% by 5% or more; and (c) two linear downward sloping segments located between the other two, with the right-hand one having a shallower slope. The slope of these two lines changes at a point where capacity equals the IRM, and price equals CONE minus [sic] the average E/AS gross margin, divided by one minus the forced outage rate [for the Reference unit]."[122]

The final proposed curve appears to be Alternative 4, in which the base curve has been shifted "1 percent to the right." This appears to mean that the "kink" in the curve is moved right so that it is one percent higher than the 15 percent reserve target (i.e., 16 percent), but the zero crossing point is *not* moved to the right (it is still at 20 percent reserves). The effect of shifting the kink, and only the kink, one percent to the right is to make the slope of the left side of the curve slightly flatter but also to extend that part of the curve further to the right, increasing total capacity payments during periods when reserves are below the target level.

According to PJM, its economic analyses show that among the alternatives considered, alternative curve 4 would achieve the highest degree of compliance with the Installed Reserve Margin (IRM) requirement. PJM claims this curve would induce investments such that the region would achieve reserve levels equal to or greater than the IRM 98 percent of the years, with average reserves expected to be only 1.79 percent above the 15 percent IRM target.[123]

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[121] PJM Filing at 62-66. The economic analyses comparing the expected investment costs and performance under each alternative curve was performed by Professor Benjamin Hobbs with evaluation from Andy Ott. See, PJM RPM Filing, Tab E, Affidavit of Andrew L. Ott (Ott Affidavit) at 17 and Tab H, Affidavit of Professor Benjamin F. Hobbs, (Hobbs Affidavit). To perform his analyses, Professor Hobbs developed "a dynamic model that simulates generation investment over time in response to incentives in the energy, ancillary services and capacity markets." Hobbs Affidavit at 6.

[122] PJM Filing, at 62.

[123] The ISO-NE claims for its proposed demand curve are more modest. While noting that the ISO-NE curve might work better than the ISO assumed, the ISO claimed only that its curve would not fall below the reliability criterion more than 17 percent of the years, and thus be at or above that criterion 83 percent of the years, compared to the PJM claim for its curve of 98 percent at or above the criterion. At C_{target}, the average reserve claimed by ISO-NE would be about 5 percent above the criterion, compared to the 1.79 percent claimed by PJM, suggesting much lower variability relative to the target for the PJM curve. Note, however, these are only the claimed results; there has been no attempt to systematically compare the different analyses performed by the two ISOs. Recall that ISO-NE *assumed* the variability resulting from its curve would be the same as experienced historically, but ISO-NE did not explicitly predict how its curve would perform, whereas PJM is attempting to predict the variability its curve will experience. Another part of this difference may be driven by the difference between ISO-NE's monthly auctions and PJM's four-year forward auctions.

Alternative curve 4 also has the lowest total consumer payments, though only slightly different from Alternatives 3 and 5.[124]

According to the analysis performed by Professor Hobbs, the principal effect of the "1 percent shift to the right" relative to the base curve is to increase the percentage of years in which the amount of capacity would meet or exceed the 15 percent reserve target (from 92 percent to 98 percent), while slightly decreasing the total costs to consumers. Although this shift slightly increases the amount of capacity, the increased capital cost is more than offset by the decrease in scarcity payments for energy.[125]

Determination of Auction Prices Under RPM

Unlike ISO-NE's proposal, PJM would define auction market clearing prices based on the intersection of the administratively defined demand curve and a supply curve composed of the capacity price offers of eligible capacity providers, as well as equivalent offers derived from offers by merchant transmission providers to expand the transfer capability between a generation LDA and load LDA. Demand response proposals meeting resource adequacy criteria would also be allowed to compete. Sellers of capacity resources with offers at or below the clearing price would be committed to meet their respective LDA's capacity requirements in the Delivery Year and would be paid the clearing price in the Delivery Year.[126] The proposal also includes a form of shortage pricing, so that if offered resources are insufficient to meet the VRR (demand) curve, the clearing price would be set by the demand curve.[127]

Using a Variable Resource Requirement curve means that PJM would at times acquire more capacity than required for a fixed resource requirement, such as 15 percent reserves. But the slope of the proposed VRR curve is such that when PJM acquires more than the 15 percent reserve level, the total cost of capacity is less than what PJM would pay if the reserve level could somehow be kept right at 15 percent.[128]

Settlements would be on a net basis for loads that owned generation or had bilateral contracts with generation. Load serving entities with bilateral or owned generation would offer their capacity into the auction at a "price taker" bid. Each LSE would receive or pay the

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[124] A table summarizing the expected performance of the alternative curves analyzed by Professor Hobbs is shown at PJM RPM Filing at 65, Table 3.

[125] PJM RPM Filing at 65; Ott Affidavit at 25.

[126] Ott Affidavit at 8. However, capacity resources with lower offers but with operating constraints might be rejected in favor of capacity resources with slightly higher offers but without such constraints. The auction algorithm would optimize these choices.

[127] Ott Affidavit at 8, and see Figure 5, Ott Affidavit at 10.

[128] This result is illustrated by Figures 5 and 6 in Ott Affidavit at 10.

Capacity Price for their net capacity (UCAP) sales or purchases, relative to their pro rata UCAP requirements.[129]

With respect to demand-side capacity resources, PJM notes that these can receive credit in energy markets but currently there is no way for them to receive credit for capacity. By allowing demand resources (DR) to participate in the RPM auctions, PJM intends to provide a means for DR to recover capital requirements that might not otherwise be recoverable from energy market revenues only. DR that wished to bid into the Base and Supplemental auctions would be called "demand as a resource." DR that did not participate in any auction could still be eligible for capacity payments by offering ILR – interruptible load for reliability – as late as three months prior to the Delivery Year. To be eligible, an ILR must meet the current requirements for PJM's existing "Active Load Management" program. ALM resources may offer up to 10 6-hour interruptions per year when called upon by PJM. An ILR provider would receive a credit against its RPM reliability charge, which will offset both the regional charge and the Locational Price Adder for the provider's LDA.[130]

With respect to transmission resources, an eligible transmission upgrade must (1) increase the CETL into an LDA, (2) demonstrate that it will be in service at the beginning of the Delivery Year, and (3) be funded by the proponent through a specified rate. The planned upgrade must have, at least 45 days prior to the auction, a certificate from PJM indicating its increase in the CETL and a signed Facilities Study Agreement, and be consistent with the most recent RTEP. The transmission alternative's offer price would be expressed in terms of the Locational Price Adder (that is, the amount by which the upgrade increases the Capacity Emergency Transfer Limits (CETL) and creates the ability to capture the difference between the capacity price in the load zone and the capacity price in the generator's zone).[131]

RPM auction prices would vary by season

PJM proposes that RPM auction prices vary by season. To allow this, resources would have the option to vary the price (but not the quantity) of their resource offers by season. PJM would then clear the auctions separately for each season of a Delivery Year. While an offer from a generation resource would be for a fixed quantity for the entire Delivery Year, the resource might not clear the auction in every season of that year; in that event, it would be obligated to provide the capacity only in the seasons in which its capacity cleared the auction. A demand resource (ILR) could submit a bid only for a season, such as summer. If its bid cleared the auction, it would be obligated to provide the ILR resources only during the season for which it

[129] PJM Filing at 53; Ott Affidavit at 12-13. Ott notes that there may be differences between the clearing prices in the Base Auction and the final net settlements, due to additional capacity purchased in the 2nd supplemental auction, missed estimates of the amount of ILR (interruptible load resources) obtained by the Delivery Year, and different prices for resources that do or do not have the two specified generator characteristics (quick start and load following).

[130] Ott Affidavit at 27. The ILR offset would not offset that extra portion of the reliability charge that pays for the specified generation features of load following and 30-minute start capability.

[131] Herling Affidavit at 15-16.

cleared the auction. Resources that submitted the same price offers for the entire year and cleared the auction (at the average clearing price) would receive a price equal to the average of the four seasonal clearing prices.[132]

Mitigation of Market Power Under RPM

Given an approach that allows resource offers to determine prices, there would be an opportunity to increase auction clearing prices through either physical or economic withholding. The RPM proposal contains mitigation approaches for both physical withholding and economic withholding.

To address physical withholding, the PJM Market Monitor would compare known amounts of capacity owned by various parties with capacity actually offered in the auctions either by the generation owner or by a load with bilateral contracts, along with evidence of capacity that had been delisted for possible export to neighboring markets. Each unit must offer its expected level of unforced capacity (UCAP) into an auction for all four seasons of the Delivery Year to be eligible for payments that year, with the UCAP rating reflecting an EFORd equal to or better than the average of the previous 12 months. The only exceptions to the implied "must offer" obligation would be for units expected to be out for the Delivery Year, capacity contractually committed to sales in another market, or units originally interconnected as energy-only units. Capacity not offered and not excepted would not be allowed to sell capacity in any way during the Delivery Year. Evidence of physical withholding would then be subject to further investigation and possible remedies, including a request for a FERC Order to compel a resource owner to offer its capacity into the auction. An auction could be delayed to allow PJM to pursue this remedy.[133]

To address possible economic withholding, the Market Monitor would first determine whether an LDA was structurally competitive, using three different tests; if an LDA failed these tests, resource offers within that LDA would be subject to potential mitigation prior to the end of each auction. The Market Monitor would compare resource offers for each unit against predetermined estimates of what competitive offers should be. A competitive offer would be assumed to equal the incremental costs for each unit of providing capacity from that unit, which would be based on that unit's total annual avoidable costs less net revenue that unit would receive from other PJM markets.[134] Offers above these estimates would then trigger a screening analysis of the price effects, and if this screen were failed, offers would be mitigated.[135]

Market structure screens would define the need for mitigation

Under RPM, PJM would first determine whether PJM as a whole, or any LPA region, required market power mitigation. PJM would apply a "preliminary screen" to determine whether the

[132] Ott Affidavit at 28-28
[133] Bowring Affidavit at 22.

[134] Bowring Affidavit at 17.

[135] Bowring Affidavit at 23.

conditions in the applicable region would permit the exercise of market power. This screen would consider the unforced capacity available to the region for the delivery year, the demand for capacity in the region for that year, and firm obligations to sell unforced capacity from resources in the region. After accounting for any transmission limits into the region, PJM would compile a potential supply curve for meeting the remaining demand for capacity. This curve would be evaluated for the potential to exercise market power.[136]

The preliminary screen would consider three tests: (1) the market shares of individual sellers, with "failure" occurring for any seller with a share in excess of 20 percent; (2) market concentration, with failure defined as an HHI greater than 1800; and (3) a pivotal suppliers test, with failure occurring if there were three or fewer pivotal suppliers – that is, the market could not clear without the supply from these three or fewer suppliers. Failing any one of the three tests would trigger data requirements from sellers and further examination of the need for possible mitigation, but the third screen ("no three pivotal suppliers") is critical. According to PJM, failing the first two screens triggers a demand for more data, but failing the third screen would trigger offer caps:

> "Only the [three pivotal supplier test] is needed because, if it is passed, no mitigation is needed regardless of the outcome of market share and HHI tests, whereas, if it is failed, mitigation is needed regardless of the outcome of the other tests."[137]

In other words, if there are four or more pivotal suppliers, the market is deemed competitive enough not to require mitigation, but if there are three or fewer pivotal suppliers, offer cap mitigation is assumed to be needed when transmission is binding.

PJM would thus apply this structural test in each auction. If a transmission constraint into an LDA became binding in solving the auction, the market structure test would be applied. If it failed, offers into the LDA experiencing the constraint would be subject to unit specific market seller offer caps. These offer caps would thus be applied in the auctions, but only if the constraints into an LDA (or PJM as a region) were binding so as to create different prices (a positive locational price adder), *and* "if the sell offers that are available to the PJM auction clearing algorithm to resolve the local constraints fail the market structure test."[138]

However, sell offers from new entrants would not be subject to offer caps, because "new entry is assumed to be competitive." An offer based on "new entry" would require an executed facilities study agreement or an interconnection service agreement prior to the auction.[139]

[136] Bowring Affidavit at 18.

[137] Bowring Affidavit at 19.

[138] Bowring Aff. at 21.

[139] Bowring Aff. at 22.

Design of market seller offer caps

PJM would develop offer caps on a unit specific basis, in an effort to emulate "competitive" offers. PJM defines a competitive offer as:

> " . . .the annual avoidable cost of the unit, less net revenues from other PJM markets, including the bilateral sale of any product from the unit. This is a competitive offer because it reflects the incremental cost of capacity for a year. If a unit has avoidable costs of $100 per MW-day and net revenues from other PJM markets of $30 per MW-day, the increment cost of maintaining the unit for a year in order to sell capacity is the difference, $70 per MW-day."[140]

Avoidable costs would be costs that the seller would avoid if the unit shut down. This might include capital investment costs that the owner might need to incur to keep a unit operable during the Delivery Year. Compared to previously approved avoidable costs to defer a retirement, PJM would include a 10 percent adder to reflect uncertainty associated with avoidable costs four years out. The net revenues from other PJM markets would be determined on a unit specific basis.[141]

The design of seller offer caps would also take into account three factors: (1) the risks that a unit's EFORd might change in the period between the auction and the Delivery Year; (2) opportunity costs faced by a unit; and (3) firm obligations to sell. With respect to opportunity cost, PJM would recognize the ability of a unit to sell its capacity into a neighboring market outside PJM. If a unit could document this opportunity, an offer into the PJM market at this opportunity cost would not be mitigated. Similarly, PJM would recognize a unit that had a firm obligation to sell, such as through a bilateral contract, an obligation to serve own loads or to serve default supply obligations. These sellers would be required to offer their capacity into the PJM RPM auctions as price takers.[142]

PJM would specifically design the offer caps to account for EFORd risks, recognizing that EFORd is an "historical measure" that may not reflect the amount of UCAP a unit might have available during a Delivery Year.

> "[EFORd] is a relatively week incentive for capacity resources to perform in the delivery year. EFORd risk in the RPM derives from the fact that an EFORd rate must be specified at the time an existing unit is offered into the RPM auction while the amount of unforced capacity actually sold [provided] in the delivery year depends on the 12 month EFORd for a period ending three months prior to the delivery year."[143]

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[140] Bowring Aff. at 19.

[141] Bowring Aff. at 19, 23.

[142] Id. at 21.

[143] Id, at 20.

To allow capacity sellers to address this risk when fashioning a "competitive offer" for an offer cap, PJM proposes to allow a part of each unit's capacity to be offered at the net cost of new entry. Each unit subject to offer mitigation would thus be allowed a base offer defined by the avoidable costs net of market revenues for most of its capacity and an "EFORd offer segment" defined by the net CONE. The idea is that the net CONE is what a seller would have to pay in the auction for any UCAP not supplied by its unit as a result of a worsening of its EFORd rate. To reflect expected variations in EFORd, the amount of capacity subject to the EFORd offer segment would be the difference between a unit's five year average and 12 month average EFORd ratings, or some other expected difference anticipated for each unit if that could be documented.[144]

Continued Use of UCAP as the Availability Metric

There do not appear to be any changes from the current availability metric. Further, PJM would continue to rely on the current system of "deficiency charges" to penalize resource providers for any failure to perform in making their resource available during the Delivery Year. There would be additional rules applicable to new transmission and demand-side response providers.[145]

[144] Id. at 20-21.

[145] PJM Filing at 55.

Figure 12
Locational Deliverability Areas, 2006/2007

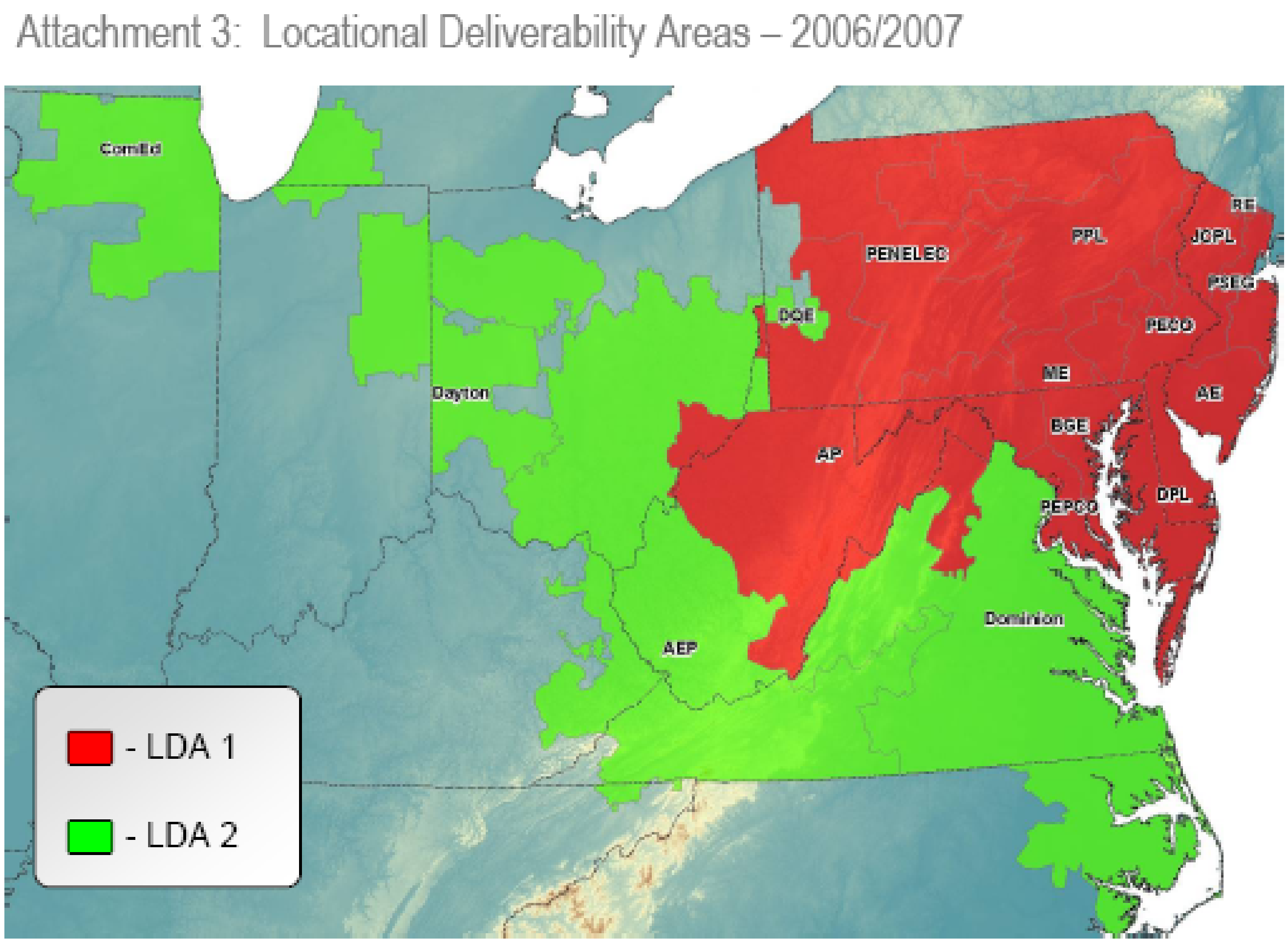


Figure 13
Locational Deliverability Areas, 2006/2007

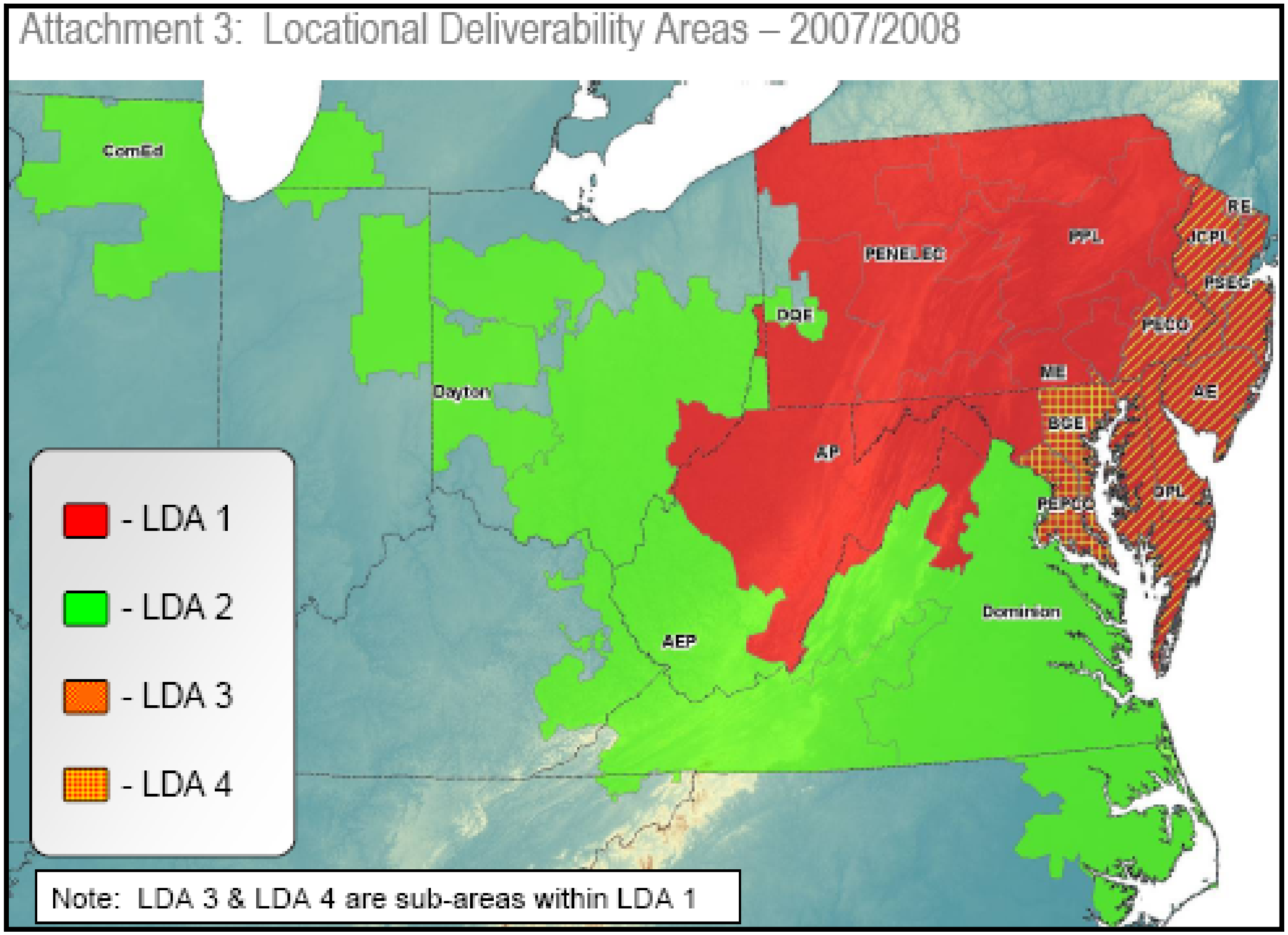
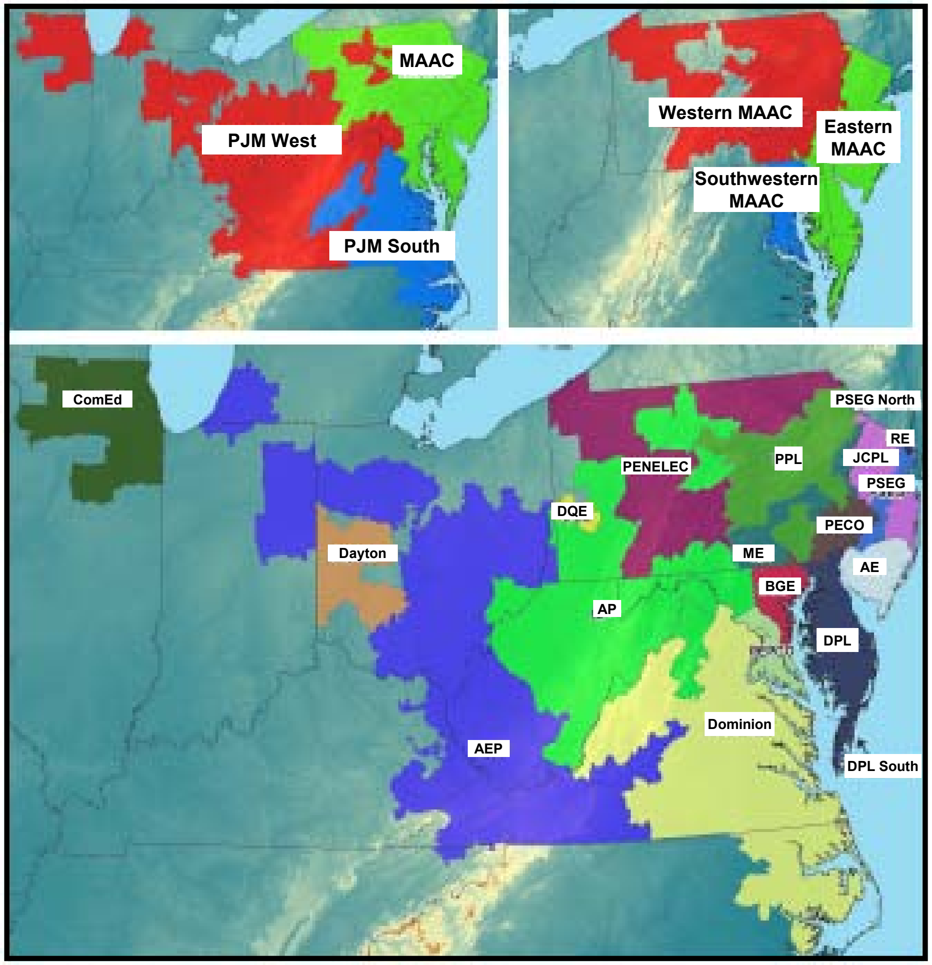


Figure 14
Locational Deliverability Areas – 2008/2009 and 2009/2010



Tables 2 and 3: Comparison of ISO Locational Features

Internal Capacity Transfer Limits

	Explicit	Model exports from LICAP regions	Model multiple nested LICAP regions
NYISO	No	No	No
ISO-NE	Yes	Yes	Yes
PJM RPM	Yes	No	No

Internal Capacity Transfer Rights

	Explicit	Financial	What determines quantity	Allows preferential allocation	Who gets the rights?	What rights do import constrained LSEs get?	Follow the load
NYISO	No	No	Difference between NYCA and Locational capacity requirement	No	LSEs in the import constrained areas	On their immediate import constraint	Yes
ISO-NE	Yes	Yes	LICAP Region import constraint	Yes	LSEs in the import constrained areas (and resources in export constrained areas as in March 1 filing)	On all import constraints into their LICAP region	Yes
PJM RPM	Yes	Yes	LDA import constraint	Yes	LSEs in the import constrained areas and MPs that bear the cost of incremental capacity	To deliver capacity from the rest of PJM	Yes

APPENDIX A: FERC ORDERS AND FILINGS RELATING TO THE PJM RPM PROPOSAL

April 2, 2003

- Reliant Energy Mid-Atlantic Power Holdings, LLC ("Reliant") submits a complaint against PJM Interconnection LLC (PJM) alleging a significant design flaw in PJM's market design such that it fails to appropriately reflect and compensate Reliant generators that provide reliability services. Reliant proposes an interim tariff design to remedy the shortcomings of the PJM market until an alternative plan can be instituted. Reliant then proposes an alternative market design including three main components: (1) identification of Reliant generators subject to the proposal, (2) new provisions for mitigation of these facilities, and (3) a CT Proxy design similar to the one created by the New England ISO. The CT Proxy system would allow generators to bid up to a "safe harbor" threshold without mitigation in order to recover high costs necessary for providing reliability.
- *Request for Approval of a Formula Proxy CT Methodology for Certain Reliant Energy Mid-Atlantic Power Holdings, LLC Generating Facilities in PJM Interconnect* in FERC Docket EL03-116-000 (April 2, 2003 Filing)

July 9, 2003

- FERC denies Reliant's April 2, 2003 complaint, explaining the Reliant has not provided significant data showing that its units in PJM could not recover fixed and variable costs. The Commission also states that Reliant also did not show that the mechanism designed by PJM does not provide units with a reasonable opportunity to recover their costs, nor did it show that the offer caps set by PJM provide insufficient revenues to create incentive for new entry. While it rejects Reliant's complaint, the Commission also notes that the current provisions in the PJM region may not be the most appropriate for providing cost recovery to reliability must run (RMR) units, and directs PJM to file a revised Tariff or justification for its existing Tariff by September 30, 2003.
- *Order Denying Complaint* 104 FERC ¶ 61,040 (July 9, 2003 Order)

September 30, 2003

- PJM submits a filing in compliance with FERC's July 9th order amending its Open Access Transmission Tariff. PJM proposes revising the price cap rules for RMR generators, but says that it will continue to cap prices on units dispatched out of economic merit for reliability purposes. PJM also acknowledges the need to modify its local market rules to effectively address long-term scarcity should such a condition arise. They propose a competitive auction to be triggered when long-term scarcity is identified in a load pocket. The filing also includes proposes eliminating price capping in load pockets deemed competitive by PJM, as well as eliminating the existing exemption of post-1996 generating units from capping provisions.
- *PJM Interconnection LLC* in FERC Docket EL03-236-000 (September 30, 2003 Filing)

December 19, 2003

- FERC issues an order recognizing that the issue of how to price RMR generators has arisen in other regions that PJM, and that it has important implications for generation infrastructure and the operation of an efficient wholesale marketplace. Therefore, the Commission orders the establishment of a two part technical conference on February 4th and 5th, 2005. The first part of the conference is to focus on the broad issue of pricing RMR units, and the second on PJM's specific proposal filed on September 30th.

– *Order Establishing Staff Technical Conference* 105 FERC ¶ 61,312 (December 19, 2003 Order)

May 6, 2004

- FERC order announcing the establishment of a general Reliability Compensation Policy. In this order, the Commission states while there may not be one uniform solution to Reliability Compensation Issues in every region, the approach to resolving these issues should be uniform and transparent. The Commission then provides step-by-step guidance for developing the most effective solutions possible. The Commission also rules on PJM's September 30, 2003 filing in this order. They find that PJM's current methodology for price capping works effectively to mitigate market power in a manner that is fair to most generating units. They propose two changes to the Tariff to provide clear rules for PJM and its generators. The first is that PJM must provide units that are frequently mitigated the right to receive higher price caps or alternative compensation, where frequently mitigated units are those that are mitigated for 80% or more of their run hours, are needed for reliability, and are not recovering sufficient revenues to cover their costs. The second FERC directive is that PJM must provide a process for procedure if bilateral negotiations between PJM and RMR units fail. The Commission also orders PJM to investigate the use of alternative pricing that recognizes operating reserve deficiencies in the market design.

– *Order on Tariff Filing* 107 FERC ¶ 61,112 (May 6, 2004 Order)

July 16, 2004

- PJM submits a compliance filing in response to the Commission's order on May 6, 2004. PJM alters the rule that suspends price capping in any hour in which there are not three or fewer generation suppliers available for dispatch, or the "no three" rule, establishing it as a clearly stated trigger for the suspension of offer caps.

– *PJM Interconnection LLC (Compliance Filing)* in FERC Docket EL03-236-002 (July 16, 2004 Filing)

November 2, 2004

- PJM submits a second filing in compliance with FERC's May 6, 2004 order, which directs PJM to address compensation for frequently mitigated units as well as to investigate the expected impacts of adopting a pricing system that recognizes operating reserves shortages. PJM revises the Tariff to say that a frequently mitigated unit shall now have an offer cap of its incremental operating costs plus $40 per megawatt hour, or that an alternative cap may be specified in unit specific agreements between PJM and the generator owner. The new Tariff also dictates that agreements between PJM and generator owners will are not effective until they are accepted by the Commission. Addressing the issue of the effect of a pricing system that recognized operating reserve shortages on its current market design, PJM states that its current market design already ensures sufficient operating reserves and therefore does not need to consider alternative pricing to address scarcity conditions.

– *PJM Interconnection LLC (Compliance Filing)* in FERC Docket EL03-236-003 (November 2, 2004 Filing)

January 25, 2005

- FERC denies in part and grants in part requests for rehearing of the compliance filings submitted by PJM on July 16, 2004 and November 2, 2004. It accepts PJM's report that it does not need to consider alternative pricing to address scarcity conditions. The Commission directs PJM to implement the revised "no three" rule that PJM proposed in the July 16th order. The order also requires PJM to file another clarification and revised Tariff sheet within 30 days of the issuance of the order.

– *Order on Rehearing and Compliance Filings and Terminating Proceedings* 110 FERC ¶ 61,053 (January 25, 2005 Order)

February 24, 2005

- Reliant submits a request for the rehearing of FERC's January 25, 2005 order based on two main specified errors: (1) the "no three" rule proposed by PJM is not just and is unreasonable and (2) the Commission made an error in applying the grandfather provisions related to post 1996 units based upon the date which the unit's zone was approved for integration into PJM. Reliant says that the Commission's approval of the flawed "no three" test, even in the interim until a more appropriate test can be implemented, serves only to hinder competition in the electricity market in the future, and offers several alternatives tests. Reliant goes on to suggest that rather than applying to grandfather provisions based upon the date of generator's integration into PJM, the Commission should adopt a rebuttable presumption that generators constructed between April 1, 1999 and September 30, 2003 have relied on the exemption in the past and therefore should continue to receive it.

– *Request for Rehearing and Clarification of Reliant Energy, Inc* in FERC Docket No.s EL03-236-001, EL03-236-002, EL03-236-003, and PL04-2-000 (February 24, 2004 Reliant Complaint)

- PJM submits a compliance filing proposing eliminating the blanket exemption for post 1996 generating units from offer capping as directed by FERC in its January 25, 2005 order. The filing also includes Tariff revisions requiring that agreements for alternative price caps for frequently mitigated units be filed with the Commission for informational purposes only, and stating that they will become effective the day after such a filing is made.

– *PJM Interconnection LLC (Compliance Filing)* in FERC Docket EL03-236-005 (February 24, 2005 Filing)

July 5, 2005

- FERC order generally denying rehearing of the Commission's January 25, 2005 Order, but granting rehearing in part with respect to scarcity pricing, particularly with respect to the prices for units that are mitigated during scarcity conditions.

The Commission sets for rehearing whether mitigation prices need to be adjusted during scarcity conditions and allows parties to raise whether even in non-mitigated markets, scarcity pricing may be necessary.

– *Order on Rehearing, Clarification, and Compliance Filings, Establishing Further Hearing Procedures, and Consolidating Proceedings* 112 FERC ¶ 61,031 (July 5, 2005 Order)

August 4, 2005

- PJM submits compliance filing in response to the Commission's July 5, 2005 order. PJM proposes Tariff updates that allow a generator to deactivate if it notifies the Transmission Provider of its intent 90 days in advance, regardless of whether it would adversely affect system reliability. The revised Tariff also requires the Transmission Provider to give at least 30 days notice to the generator owner of the date where its operation is no longer needed for system reliability, and allows generators to recover project investment costs if PJM determines that the unit is no longer needed for reliability.

– *PJM Interconnection LLC* in FERC Docket EL03-236-008 (August 4, 2004 Filing)

August 31, 2005

- PJM submits for approval its Reliability Pricing Model, proposed as a replacement for its current capacity pricing model. The new RPM proposes valuing capacity by location and utilizing a downward sloping demand curve in annual auctions. The auctions would be for resources to be delivered four years later, with the four-year forward commitment allowing planned new generation and transmission upgrades to compete with existing generation to meet resource adequacy requirements. Higher prices would be paid to capacity resources with that can provide 30-minute reserves (quick start) and load-following capability. PJM further proposes explicit market power mitigation rules to address capacity market structure concerns.

– *PJM Interconnection LLC*, filed in Docket ER05-___-000 and EL05___-000 (August 31, 2004 Filing)

APPENDIX B: FERC ORDERS AND FILINGS RELATING TO ISO NEW ENGLAND LICAP PROPOSAL

September 20, 2002

- FERC accepts a new Standard Market Design (SMD) proposal for New England, which will replace the existing New England Power Pool (NEPOOL) market rules with the proposed Market Rule 1. Included in the SMD design is a *pro forma* reliability-must-run (RMR) agreement, which can be negotiated by ISO New England to help expensive, seldom run units recover high fixed and operating costs. To be eligible for an RMR contract, the unit must be necessary for reliability and the unit would be retired if no contract were approved. These requirements assume that most of these units are located in high congestion energy pockets known as designated congestion areas (DCAs), such as in Southwestern Connecticut.

– *Order Accepting in Part and Modifying in Part Standard Market Design Filing and Dismissing Compliance Filing* 100 FERC ¶ 61,287 (September 20, 2002 Order)

December 20, 2002

- FERC grants in part and denies in part requests for rehearing of the Commission's September 20, 2002 Order and approves the new CT Proxy system proposed by the New England ISO. The proposal said that a CT Proxy price high enough to recover fixed costs may serve as a safe harbor bid during all hours for RMR units, and that that bids exceeding the CT Proxy will be subject to mitigation by the ISO. The Commission also reiterates ISO-NE's authority to negotiate RMR agreements to ensure system reliability, but cautions that the ISO must ensure that contracts are only negotiated with units that are needed to ensure reliability.

– *Order Accepting Reliability Agreements* 101 FERC ¶ 61,341 (December 20, 2002 Order)

January 16, 2003

- PPL Wallingford LLC proposes an RMR cost-of-service agreement negotiated with ISO New England for four of its units located in Southwest Connecticut. The agreements allow PPL Wallingford to continue the operation of four generating units necessary for reliability on a cost-of-service basis. In exchange for keeping the four units operating, PPL Wallingford will receive a monthly fixed cost charge to help them cover the units' variable operation and maintenance costs. The payment will be calculated using an annual fixed revenue requirement (AFRR) of $30.7 million dollars for these four units, and will be subject to reduction based on PPL Wallingford's energy market revenue.

– *Cost of Service Agreement Among PPL Wallingford Energy LLC, PPL EnergyPlus, LLC and ISO New England, Inc* in FERC Docket ER03-421-000 (January 16, 2003 Filing)

February 26, 2003

- Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, and NRG Power Marketing Inc submit RMR cost-of-service agreements negotiated with ISO New England. The filing explains that these four generating stations, which are necessary to maintain reliability throughout Connecticut, are located in DCAs in the Southwest portion of the state. The units are rarely dispatched in economic merit, and therefore have limited opportunities to recover their high operating costs. The proposed agreements would allow these units to bid up to a given safe harbor price, defined as the incremental operating cost of a hypothetical combustion turbine (CT) generator plus the unit's annual fixed costs, calculated based on expected number of operating hours for that year. The parties in the agreement believe that this safe harbor threshold will allow these units to more effectively recover their costs.

– *Reliability Agreements Among Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, NRG Power Marketing Inc., and ISO New England Inc.* in FERC Docket ER03-563-000 (February 26, 2003 Filing)

March 25, 2003

- FERC issues an order allowing ISO-NE to collect costs associated with the Reliability Projects described in the February 26, 2003 filing. The order allows ISO New England to disburse the funds to the generators involved in the agreements to ensure that they are adequately maintained for the summer peak season.

– *Order on Joint Emergency Motion* 102 FERC ¶ 61,314 (March 25, 2003 Order)

April 25, 2003

- FERC rejects Devon Power LLC et al's filed cost-of-service agreement (February 26, 2003 Filing) and permits the proposed contracts to recover only certain going-forward maintenance costs. The Commission says that expensive units under RMR agreements receive greater revenue than new market entrants, who are receiving suppressed revenues from the lower spot price resulting from existing RMR contracts. The Commission directs ISO New England to develop a market based mechanism to reduce the use of RMR contracts. In the interim, FERC suggests a system that would allow seldom run units to raise their bids to a Peaking Unit Safe Harbor (PUSH) limit, defined as the sum of its fixed and variable costs divided by the number of megawatt hours supplied in the previous year. FERC asserts that the PUSH bid system will help high cost, seldom run units necessary for reliability to recover their fixed costs through the energy market rather than through RMR contracts. The order also removes the previously approved CT Proxy system (December 20, 2002 Order).

– *Order Accepting, in Part, Requests for Reliability Must Run Contracts and Directing Temporary Bidding Rules* 103 FERC ¶ 61,082 (April 25, 2003 Order)

June 6, 2003

- FERC grants in part and denies in part New England ISO's request for a rehearing and/or clarification in response to its September 20, 2002 Order. FERC denies the request for a rehearing of its decision to allow ISO New England to designate DCAs, asserting that it is the existence of a load pocket and not the designation of a DCA that imposes costs and difficulties on the market. The Commission also reaffirms its approval of the PUSH bid system over a CT Proxy system for cost recovery for expensive, seldom run units.

– *Order on Rehearing and Accepting in Part and Rejecting in Part Compliance Filings* 103 FERC ¶ 61,304 (June 6, 2003 Order)

May 16, 2003

- FERC rejects a proposed reliability-must-run agreement submitted by PPL Wallingford (January 16, 2003 Filing) based on their findings regarding the Devon Power LLC RMR agreement detailed in its April 25, 2003 Order. FERC maintains that the PUSH bid system set forth in the Devon decision will allow higher prices during hours when demand approaches capacity limits through the market rather than through RMR agreements. The Commission argues that all generators, including PPL Wallingford, will receive these high prices, and this should help them to recover their costs.
- – *Order Rejecting Reliability Must Run Agreement* 103 FERC ¶ 61,185 (May 16, 2003 Order)

March 1, 2004

- ISO New England submits a filing in compliance with FERC's April 25, 2003 Order that proposes implementing locational or deliverability requirements in the installed capacity (ICAP) market. The proposal is a response to FERC's directive that ISO New England create a market-based mechanism that will reduce the need for RMR agreements. The proposed LICAP system seeks to reduce reliance on RMR agreements by both introducing a locational element into the capacity market and by replacing the existing vertical demand curve with one that is downward sloping. The ISO proposes that its LICAP system replace the PUSH bid system ordered by FERC in its April 25, 2003 Order, and that LICAP be implemented by ISO New England no later than June 1, 2004.
- – *Compliance Filing of ISO New England, Inc.; Devon Power LLC, et al* in FERC Docket ER03-563-030 (March 1, 2004 Filing)

June 2, 2004

- FERC agrees with two broad concepts in ISO New England's March 1, 2004 LICAP proposal: (1) it is appropriate to establish ICAP regions and (2) the use of a demand curve in the ICAP market is reasonable. However, the Commission expresses concern that the regions set by New England do not adequately reflect the need for infrastructure investment in some areas, especially in Southwestern Connecticut. To that end, the Commission suggests that Southwestern Connecticut be designated as a separate ICAP region. The Commission also requests more information regarding the parameters of the sloped demand curve that the ISO proposed, and orders that a public hearing be held to discuss the appropriate methodology for determining the parameters of the demand curve. The order also extends the use of the PUSH mechanism in New England until LICAP can be fully implemented.
- – *Order on Compliance Filings and Establishing Hearing Procedures* in FERC Dockets ER03-563-030 and EL04-102-000 (June 2, 2004 Order)

July 2, 2004

- ISO New England submits a compliance filing in accordance with FERC's June 2, 2004 Order that directed the ISO to address the designation of Southwest Connecticut as a separate load zone. The ISO's analysis supports the findings of the Commission that Southwest Connecticut should be a separate ICAP region and energy pricing zone for load, as differences in transmission constraints between this area and the rest of the state will likely lead to an ICAP price difference.

- *Compliance Filings of ISO New England, Inc.* in FERC Dockets ER03-563-039 and EL04-102-002 (July 2, 2004 Filing)

November 8, 2004

- FERC denies request for rehearing and denies in part and grants in part clarification of the June 2, 2004 Order in which the Commission agreed with two broad concepts of ISO New England's LICAP proposal (establishing ICAP regions and introducing a demand curve).
  - *Order on Rehearing and Clarification* 109 FERC ¶ 61,154 (November 8, 2004 Rehearing Order)
- FERC issues an order accepting ISO New England's July 2, 2004 Filing, and amends the ISO's earlier LICAP proposal to include Southwest Connecticut as a separate ICAP region and energy pricing zone for load.
  - *Order on Compliance Filing* 109 FERC ¶ 61,156 (November 8, 2004 Compliance Filing Order)

November 2004-February 2005

- FERC holds hearings before an Administration Law Judge as ordered in its June 2,2004 Order. These hearings are to litigate the appropriate methodology for determining transfer capacity limits and demand curve parameters to be used in each LICAP region.

March 23, 2005

- FERC denies request for rehearing and denies in part and grants in part requests for clarification of its November 8, 2004 Rehearing Order. The Commission reiterates that it is their goal to develop a market-based mechanism that allows generators necessary for reliability to recover their costs without reliance on RMR contracts. They order that under the LICAP mechanism, all generators, not merely new entrants, located in a given LICAP region should receive the same LICAP price.
  - *Order on Rehearing and Clarification* in FERC Dockets ER03-563-047 and EL04-102-007 (March 23, 2005 Rehearing and Clarification Order)
- FERC denies requests for rehearing of its November 8, 2004 order that Southwest Connecticut be made a separate LICAP and energy load zone.
  - *Order on Rehearing* in FERC Dockets ER03-563-048 and EL04-102-008 (March 23, 2005 Rehearing Order)

June 15, 2005

- Initial Decision issued by the Administration Law Judge in the LICAP procedure finds that the ISO New England Demand Curve proposal provides a just and reasonable method for compensating generators necessary for reliability as a whole. The Decision also finds that LICAP is a reasonable method for attracting and retaining the necessary infrastructure to assure long-term reliability at the lowest cost to consumers. In addition, the Administration Law Judge (ALJ) orders that appropriate reductions be made to the proposed LICAP payments to account for peak energy rents. The decision also asserts that the ISO's mitigation procedure is essential to successful LICAP implementation, and that the price setting system proposed by the ISO is appropriate. However, the ALJ rejects ISO

New England's proposal to base payments on availability during operating reserve shortages, saying that the ISO has not met its burden of showing that its current approach for determining ICAP payments is unjust and unreasonable such that it should be replaced with the shortage hour approach.
  - *Initial Decision* 111 FERC ¶ 63,063 (Initial Decision)

June-July 2005
- The New England Congressional Delegation, Governors, and Attorney Generals from the six New England states send opposition letters to the Commission urging it to reject ISO New England's LICAP proposal. They express their concerns that LICAP will increase residential electricity costs, and that the "experimental and radical plan" proposed by the ISO may not result in new capacity infrastructure in New England. The Congressional Delegation includes a series of questions that they request be answered by the Commission regarding the ISO's LICAP proposal.
  - Letter from the New England Congressional Delegation to FERC Chairman Kelliher in FERC Dockets EL04-112 and ER03-563

July 25, 2005
- FERC Chairman Kelliher issues responses to the opposition letters received from New England officials noting that he can not discuss the case in specific detail, but pointing out that there is a serious lack of sufficient capacity in selected portions of New England and that the current pricing policy is ineffective. Kelliher indicates that the Commission is preparing a response to the questions submitted by the Congressional Delegation.
  - Letters from FERC Chairman Kelliher to New England Legislators and Congressional Delegations in FERC Dockets EL04-112 and ER03-563

August 9, 2005
- The New England Congressional Delegation requests that the Commission delay any decision on the New England LICAP proposal by one year in order to consider alternatives to the demand curve approach proposed by ISO New England.
  - Letter from the New England Congressional Delegation to FERC Chairman Kelliher in FERC Docket EL04-112-000

August 10, 2005
- FERC orders that oral arguments in these proceedings will be held on September 20, 2005. It states that it cannot commit to issuing an order on the Initial Decision by September 15, 2005 as requested by ISO New England for a January 1, 2006 LICAP implementation date. The Commission orders that the implementation of the LICAP mechanism, if it proceeds, be delayed until no earlier than October 1, 2006.
  - *Order Granting Oral Argument and Delaying Implementation of Locational Installed Capacity Mechanism* in FERC Docket ER03-563-030 (August 10, 2005 Order)

September 9, 2005
- Richard Blumenthal, Attorney General for the State of Connecticut, the Connecticut Office of Consumer Counsel, the Connecticut Municipal Electric Energy Cooperative, and the Connecticut Industrial Energy Consumers (jointly

"The Connecticut Representatives") file a request for clarification of FERC's August 10, 2005 order. The Connecticut Representatives request that FERC affirm its prior rulings that a separate load zone for Southwest Connecticut will not be implemented until and unless LICAP is implemented. The Connecticut Representatives request clarification based on FERC Commissioner Nora Mead Brownell's concurrence that suggested that a separate SWCT load zone will be implemented on January 1, 2006. The motion argues that implementing the separate zone prior to the implementation of LICAP will likely harm Connecticut energy consumers by raising prices unnecessarily, and that critical timing issues will arise if the separate zone and LICAP are not implemented at the same time.

– *Answer of the Connecticut Department of Public Utility Control, the Connecticut Office of Consumer Counsel, and Richard Blumenthal, Attorney General for the State of Connecticut to the ISO New England Inc.'s Motion for Clarification and Motion for Clarification* in FERC Docket ER03-563-030. (September 9, 2005 Connecticut Motion).

September 12, 2005

- Richard Blumenthal, Attorney General for the State of Connecticut, the Connecticut Office of Consumer Counsel, the Connecticut Municipal Electric Energy Cooperative, and the Connecticut Industrial Energy Consumers (jointly "The Connecticut Representatives") file a complaint requesting that FERC order an amendment to ISO New England's Market Rule 1. The Connecticut Representatives claim that the current "flawed patchwork of market and regulation design" cannot provide Connecticut energy consumers with fair and reasonable electricity prices. They ask that FERC order New England's Market Rule 1 to say that all generators deemed RMR units, or otherwise deemed necessary for reliability by the ISO, must apply for cost-of-service compensation agreements. The Connecticut Representatives say that the current combination of a competitive market, the PUSH bidding mechanism, and RMR contracts will cost Connecticut consumers approximately $1 billion dollars in the upcoming year.

– *Complaint Requesting Fast Track Processing and for Order to Amend ISO New England's Market Rule 1 with Regard to the Compensation of Electric Generation Facilities in Connecticut* in FERC Docket EL05-150-000 (September 12, 2005 Complaint).

September 13, 2005

- Commissions from two New England states, Massachusetts and Connecticut, jointly submit a proposed alternative to LICAP, called the New England Resource Adequacy Market (NERAM). They argue that NERAM, once fully developed, will ensure greater competition in the capacity market than LICAP, leading to just and reasonable capacity prices in New England. Unlike LICAP, NERAM does not have a locational aspect; rather, it presents a centralized, regional capacity market that supporters believe will result in lower prices for consumers. Another critical difference between NERAM and LICAP is NERAM's proposed annual auctions instead of LICAP's monthly auctions. These auctions would auction off capacity contracts three-years in advance of the delivery date, which NERAM's supporters believe would allow new market entrants to compete with existing generators to assure reasonable capacity prices. The NERAM proposal also includes a vertical demand curve in contrast to LICAP's sloped curve. Supporters of NERAM believe that the vertical curve will provide just and reasonable rates under the competition created by NERAM's market design. The NERAM market design also includes locational ancillary services and forward reserve markets, which supporters believe will produce higher compensation for resources in load pockets and eliminate the need for RMR agreements.

– *Statement in Support of the New England Resource Adequacy Market of the Massachusetts Department of Telecommunications and Energy, Connecticut Department of Public Utility Control, Connecticut Office of Consumer Counsel, New Hampshire Office of Consumer Advocate, Maine Public Advocate, NSTAR Electric and Gas Corporation, National Grid USA, Northeast Utilities Service Company on Behalf of The Connecticut Light and Power Company, Western Massachusetts Electric Company and Public Service Company of New Hampshire, Strategic Energy LLC, Associated Industries of Massachusetts, the Business Council of Fairfield County, and the Energy Consortium* in FERC Docket ER03-563-030. (Two State NERAM Support Statement)

September 13, 2005

- Commissions from four New England states, New Hampshire, Vermont, Rhode Island, and Maine, submit a proposed alternative to LICAP known as the New England Locational Resource Adequacy Market (NELRAM). Like the proposal submitted by Connecticut and Massachusetts, the NELRAM proponents advocate annual three-year lead-time auctions that NELRAM proponents claim will allow new market entrants to effectively compete with existing participants. NELRAM also includes the use of a locational forward reserve market, as incorporated in the NERAM proposal, to ensure long-term capacity availability. Unlike the NERAM proposal, however, NELRAM includes a locational pricing system for the entire capacity market, not just for forward reserves and ancillary services. NELRAM supporters say that a locational forward reserves market alone is not enough to send the proper price signals for market participants to build the correct amount of generation where it is needed. The developers of NELRAM also support investigating increasing the energy bid cap, explaining while they do not support eliminating the cap altogether, this investigation would be an important part of the overall NELRAM market design.

– *Four State Commissions Proposed Alternative to LICAP* in FERC Docket ER03-563-030. (NELRAM Proposal)