

**Electricity Policy Bulletin****Christine Tezak****202-295-2351****June 24, 2005**

## **Resource Adequacy — Alphabet Soup!**

### ***Summary:***

**PUSH****LICAP****UCAP****RPM****RMR**

These acronyms all have one thing in common. To investors, they represent programs that are designed to provide a revenue stream to generation owners in restructured markets. However, to federal and state regulators and customers, these programs are also supposed to provide market signals in lieu of the prices that customers would otherwise see, and provide the incentive needed to foster construction of new generation before a market tightens and becomes too volatile for comfort. Do they, will they, work? Or is this just another exercise in regulatory futility?

**We agree that owners of installed generation will find that some units will be more viable (and some more profitable) if these programs are implemented** during this period of negative spark spreads and overcapacity in many areas. However, we are not convinced that the majority of these programs will necessarily result in the addition of new capacity in restructured markets. In this report, we explain why.

In the absence of price-responsive demand, the maintenance of capacity reserves and the use of price mitigation both contribute to the need for generation resources to receive revenue in addition to the revenues they can earn in the energy and ancillary services markets. What has not been resolved is whether this product, which is essentially insurance against both price spikes and outages, should be treated as a private or public good. How it will be procured and priced is a central debate in today's energy markets.

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## *What is Resource Adequacy?*

In the electric power sector the term Resource Adequacy refers to the transmission provider's probabilistic ability to meet end-use demand for electric power during system peak hours. Resource Adequacy is one component of Transmission Reliability. Transmission Reliability is a measure of the transmission system's ability to meet end-use demand during all hours.<sup>1</sup> Transmission Reliability is ensured through combination of forward planning, communications and control devices, generation dispatch and ancillary services. While other network industries require analogous network reliability systems, the electric power network is somewhat unique in that most end-use customers are not provided with a marginal price signal. Therefore, the system is designed to meet peak demand by adjusting quantity rather than price<sup>2</sup> (e.g., instead of encouraging users to reduce demand by making it more expensive, they are blacked/browned out) and this leads to issues of "reliable" service.

Underlying most resource adequacy standards in the United States are criteria set by the Regional Electric Reliability Councils for generation adequacy, typically a "1 in 10 Loss of Load Expectation" or LOLE.

Each area's resources will be planned in such a manner that, after the allowance for scheduled outages and de-ratings, assistance over interconnections with neighboring regions, and capacity and/or load relief from operating procedures, the probability of disconnecting non-interruptible customers will be no more than once in ten years – *NPCC criteria on generation adequacy*.

This report focuses on resource adequacy models that are administered by independent system operators (ISOs) or regional transmission organizations (RTOs) in the United States. We are not addressing vertically-integrated utility systems outside of organized markets here because their resource planning processes and recovery from customers has not changed.

RTOs and ISOs provide unbundled transmission service and, therefore, they face unique challenges in assigning Resource Adequacy obligations and performing long-term planning. **Each RTO must balance regulatory goals with market fundamentals and not step on the toes of either the federal or state regulators in this arena where jurisdictions now overlap.**

## *How Did We Get Here?*

Prior to transmission unbundling and retail access, resource adequacy was part of the Integrated Resource Planning (IRP), a process whereby transmission owners forecast demand and determine least cost solutions for meeting demand from a choice of generation, transmission, efficiency and load control investments. The IRP is reviewed by regulators and negotiated on behalf of the captive rate payers. The 1972 Public Utility Regulatory Policies Act (PURPA) allowed entities other than utilities to construct generation and connect it to the grid without going through IRP. These new players and the arrival of retail wheeling (or "direct access"), which arrived after the Energy Policy Act of 1992 (EPAct), made IRP impractical in many states. Even before the 1992 EPAct was enacted, the 1965 Northeast Blackout changed the way resource adequacy was administered. The first thing that happened was the creation of three Northeast power pools.

Because electric generation efficiency generally increases with size, power plants became increasingly larger and capacity additions increasingly lumpy. However, complete self-sufficiency for utilities is very expensive. The power pools in the Northeast partially solved this problem by sharing loads and existing

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<sup>1</sup> The vast majority of reliability failures occur on the distribution system, where the cost per outage is considerably smaller.

<sup>2</sup> System operators are using "Marshallian equilibrium" by adjusting quantity rather than price.

capacity to reduce the impact of isolated forced outages of specific units and by instituting a pool-wide installed capacity (ICAP) requirement, and creating a new mechanism for members to share capacity.

In this way, a bundled utility could delay an investment in new generation capacity required in its state IRP by purchasing ICAP credits from another member in the pool. The benefit of pool ICAP trading is to lower the total capacity requirement for each member. Instead of needing to build to an increment above one's own peak load (say 115%), a utility could build 105% and source the other 10% from others. **The probability of more than one utility in a pool experiencing a dramatic unforced outage contingency has been deemed low enough to validate this resource sharing.**

**It is worth noting here that ICAP is not a call option.** An owner of ICAP credits has no rights to call on specific capacity from a specific seller. The RTO, however, does have the right to call on the capacity in order to keep the power pool in balance, but there is no strike price. A unit that accepts capacity payments must run if called upon. It receives the same remuneration over the term of the capacity commitment whether or not it runs. The call is only exercised during a system emergency when exports are "recalled" (*i.e.*, external resources are called). In all RTOs with resource adequacy payments, suppliers are required to offer any available resources to the pool as capacity (a "must-offer" requirement). For the system operator it is very valuable to know what resources will be available day-ahead. However, it is not clear that the must-offer requirement increases availability in any way in a market.

ICAP did not become a product traded in an organized market until states began to allow direct access for retail customers. For retail choice to remain viable, customers had to be separated from the need to source from specific generation facilities, unless by their own choice. ICAP credits created a fungible product that could be easily traded among load-serving entities (both utilities and marketers) to facilitate switching, while maintaining the static pool of capacity desired by system operators to keep the lights on.

**Charging for ICAP as a separate service allows customers in restructured markets to buy spot electricity if desired, but allows the system operator to collect the revenues needed to pay generators who may need to come on line to maintain system reliability.** In systems with retail access, but without an ICAP mechanism, the ability of the system operator to maintain resource adequacy is a choice between allowing electricity prices to rise (exponentially, if needed) to maintain system equilibrium, or requiring load-serving entities to demonstrate the ownership of a contract for capacity with a generation resource.

When there is no capacity product, each generator bids and is paid for the all power he produces and those charges are assigned directly to customers. This is called an energy-only market. If a market gets short, and prices go up, this can be very expensive on occasion. If a market is short for an extended period of time, charges to customers could be very high. When customers don't see prices, they consume all power they care to. If prices change dramatically upwards, the customer doesn't see the impact until the next billing cycle, and has no opportunity to cut consumption and avoid high charges. When high prices are passed directly to consumers that don't expect them, state regulators and politicians get very exercised.

**The debacle in California has sensitized both state and federal regulators to price volatility.** At this point, volatility in organized markets is managed through a variety of mechanisms that severely mute the price signals that should result when a market moves towards scarcity and would result in new investment.

**There is also the risk that when supply is limited, service gets interrupted.** More than an occasional interruption is considered unacceptable for both retail and commercial users. **Energy-only markets have the potential to result in an equilibrium point for the market that is not consistent with what users and regulators want to see.** ICAP markets become a vehicle for bridging the distance between the preferred reliability targets and the market's natural settling point.

Spot prices can rise above \$6,000/MWh, as they did in the Midwest in 1998 and in New England on May 8, 2000. High price spikes create political problems, and investors may assume that future price spikes will not be allowed. The alternative is to curtail customers' service, which is very unpopular.

All RTOs currently employ some form of offer cap mechanism for energy sales, usually set at \$1,000/MWh. The most commonly used control on prices is not the offer cap, which is rarely reached, but **daily mitigation procedures**. Resources that are deemed to have some form of market power (the ability to raise prices above competitive levels) are individually **offer-capped in advance**. In PJM, for example, the standard had been to cap units at 10% above marginal cost.

Another feature of many FERC-approved markets is the use of locational marginal pricing (LMP). The concept of LMP is based on the idea that the market price of any commodity should be the cost of bringing the last unit of that commodity to market. In electricity, this means giving the grid operator the option of bringing a generator into service that can provide power in order to avoid curtailing service. If the parties are willing to pay the price, the use of LMP techniques provides a financial mechanism to flow more power and more transactions over the grid. The payments go to the generators and most contracts have the buyer as responsible for covering any LMP charges that may be incurred.

**Critics of the LMP system are often frustrated by a difficulty to hedge these sometimes very volatile and unexpected costs.** The virtues and shortcomings of LMP would be the subject of a separate report altogether; nevertheless, the focus on resource adequacy in some markets has been driven in part by the combination of energy sales, LMP charges and ancillary services are insufficient to keep some units economically viable. This is particularly problematic when demand is not responsive to prices. Load that is regularly seeing high LMP prices is frequently baffled that generators still need *more* compensation.

What has not been resolved is whether the myriad variations of installed capacity products — which behave as insurance against both price spikes and outages — should be treated as a private or public good. A private good puts the onus on market participants to sort out their own options. A public good implies a more socialized assessment of the needs and costs.

How capacity reserves will be procured and priced is a central debate in today's energy markets.

### ***Federal Resource Adequacy Policy***

Under bundled service and IRP rate-making the Federal Energy Regulatory Commission (FERC) had little say over resource adequacy decisions, which traditionally were handled by the states in coordination with the regional reliability council.<sup>3</sup> However, with the advent of electric competition and the development of ISOs and RTOs, it made sense that resource adequacy be determined at the interstate level across the area of the ISO/RTO as part of the wholesale tariff. The ISOs and RTOs make it possible for independent generating companies, wholesale customers, and load serving entities (LSEs) — wires only utilities, retail marketers, and traditional utilities — to interact on a common platform. The FERC has jurisdiction over RTOs and the rates that they charge, and is responsible for ensuring that rates are "just and reasonable." This is not an easy task when states still believe they have a role in resource adequacy decisions.

When it issued Order 888 in 1996 the FERC's focus was on eliminating undue discrimination and not on resource adequacy rules. In the Northeast, parts of the Midwest and in California, several states ordered their utilities to "unbundle" the services they provide, *e.g.*, provide generation, transmission and

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<sup>3</sup> The North American Electric Reliability Council (NERC) was founded to ensure that the bulk electric system in North America is reliable, adequate and secure. Since its formation in 1968, NERC has operated as a voluntary organization, relying on reciprocity, peer pressure and the mutual self-interest of all those involved. NERC is composed of ten state regions, although three will be combining in the MidAtlantic and Eastern Midwest.

distribution as separate services. Many states (not Congress, not the FERC) required companies to sell generation assets to third parties or put them in separate subsidiaries in order to create a situation where all generators were on the same footing. Order 888 established the framework for ISOs and the concept of “network service.” Network service, however, was also to be made available by all utilities, not just those in ISOs.

Order 888 requires, among other things, transmission owners to offer “network service” to others on the same terms and conditions as it offers to itself. The network was defined in part by the area that the utility serviced as the transmission owner and identified the “network resources” that could be available to its own customers as a power source.

However, network service also had to be provided to others even in areas that were not forming ISOs. When plants began to interconnect to existing service territories, they had a choice. They could connect as either a network resource (enabling them to serve the maximum number of customers within that service territory under most circumstances) or as energy-only, which provides transmission service to the plant (and its customer) only when transmission capacity is available.

**By broadening network service beyond the transmission owner’s native load<sup>4</sup> the FERC severed the connection between IRP and load.** In the 1992 Energy Policy Act, Congress did not address the problem of what might occur when a flurry of new generation sources interconnected to the existing grid. The 1992 EPAct provides no clear identification of who is responsible for paying for the necessary investment for ensuring grid reliability when a boom of new plants are added that were not explicitly planned for in the original development of the transmission grid.

**Many utilities found that the new generation owners were not interested in helping to fund network upgrades** needed to facilitate the service reach of the new plants or make the network work better once they were connected; **independent generators generally believed that it was the transmission owner’s responsibility** not theirs. **The state regulators have little interest in authorizing recovery** into ratebase for upgrades that they believed would not be occurring but for these wholesale interlopers who were joining the system and providing no benefits to the retail ratepayers.

**We believe that this situation is a very large part of the declining trend in investment in transmission.** That declining investment<sup>5</sup> resulted in part from newer systems being implemented to manage the grid at higher utilization rates (financial transactions allow the grid operator to put more generators on line instead of curtailing transactions to manage congestions). However, now that those efficiencies have been substantively realized, we believe that **the slow pace of grid expansion stems directly from the inability to set up the appropriate tariff regime to recover investment in the high-voltage transmission grid beyond the organic growth of utility service territories or obvious reliability projects.** Even though spending ticked up a bit in 2004, it’s not forecast as a sustained reversal, just a slightly higher plateau.

In the years that followed Order 888, the commission found that functional unbundling of transmission (providing transmission as a separate service) wasn’t enough to provide the robust level of competition the commission sought to establish, and was not leading to incremental investment in transmission assets

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<sup>4</sup> Native load generally implies the traditional utility retail and commercial load that takes service under bundled rates. When markets expanded, wholesale transactions grew exponentially as independent power producers began selling both to retail marketers and to industrial customers. While native load is often used to refer to retail utility customers, technically, any buyer is that particular seller’s “native load.” Native retail utility load is scheduled first in the transmission queue, followed by firm, and then by interruptible contracts.

<sup>5</sup> While the trend may be reversing somewhat this year and next, the grid still faces challenges due to the fact that investment in generation has simply dwarfed grid expansion and upgrades.

to keep pace with generation build. In spite of more efficient operation of the grid in many areas, some independent producers began to grumble that they were not receiving network access on a non-discriminatory basis.

Still lacking the congressional imprimatur to order network transmission upgrades, the FERC issued **Order 2000 in December 1999** in an attempt to alleviate concerns about discrimination by ordering unbundling of transmission services even in areas that still provided it in vertically-integrated service territories. The FERC did not address regional resource adequacy directly in this Order either. Order 2000 required that RTOs have control over short-term reliability, including the right to redispatch generation. The RTO, however, would not have control over generation maintenance schedules.

By 2001, President George W. Bush had given Chairman Pat Wood III the charge of cleaning up the California power crisis. As an outgrowth of that effort, the commission undertook a serious effort to address a number of shortcomings in market designs above and beyond the over-reliance on spot markets that was characteristic of the California debacle and prevent the possibility of large blackouts in other areas if extreme market conditions led to curtailments. The result was a Notice of Proposed Rule making on **Standard Market Design (SMD) in July 2002**.

Like Order 2000, the FERC again expressed a concern that there was a systematic under-investment in infrastructure and remains worried about non-discriminatory use of the transmission grid. The FERC proposed a long-term resource adequacy requirement in addition to the short-term reliability duties for RTOs.

The FERC specifically stated that it would not adopt the ICAP methodology of the three Northeast power pools, and instead would require all LSEs to forward contract for supply and reserves. The role of the system operator would be to account for these resources and validate the ability of those reserves to provide power to the load it was to serve. Loads that relied on the spot market might still be served in an expensive spot market up to the point where resources were exhausted. At that point, loads without sufficient reserves to meet peak demand would be curtailed.

Despite the expressed intent “to complement, not replace, existing state resource adequacy programs,” the proposal is/was opposed by many state regulators, who believed it was an inappropriate intervention into state authority. States did not want the FERC to tell them what the reserve margin should be (some wanted more than the FERC target, others less). The proposal was also opposed by the Northeast power pools as being unenforceable as an operator as it might not be possible to target curtailments only on the entities that failed to secure appropriate supplies.

**Ultimately, the FERC was forced to effectively abandon its rulemaking due to considerable state opposition and the threats from Congress.**

Instead, the FERC issued a whitepaper on a **Wholesale Market Platform** with considerably more deference to regional differences, allowing ICAP-style markets in the Northeast and alternatives to the forward contracting it preferred to see elsewhere. The FERC also withdrew its proposed standard offer caps. For RTO markets, the system operator would only impose resource adequacy requirements when state(s) asked or “where a state does not act.”<sup>6</sup> The final SMD rule has never been issued (Congress has included language to delay it or permanently prevent it since 2003 and the commission has stopped work on the effort). This leaves unresolved the full extent of federal jurisdiction over resource adequacy rules and requirements.

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<sup>6</sup> It is not specified in the White Paper what would constitute a “failure to act.”

Section 201 of the Federal Power Act expressly precludes the FERC from ordering the construction of generation assets, and resource adequacy of vertically-integrated utilities has traditionally been regulated the states. However, as we said earlier, RTOs are jurisdictional and clearly regulated by the FERC. In addition, FERC jurisdiction extends not only over sales of wholesale energy but also to ancillary services and standby commitments provided by a generator to another party on a wholesale basis.

**The federal courts have upheld the FERC's decisions in accepting resource adequacy programs such as ICAP** and the associated rates for the New England ISO, the New York ISO and the PJM Interconnection (MidAtlantic). However, the matter of whether the FERC could impose a resource adequacy requirement over the objections of state regulators has not been resolved as it has yet to be specifically tested.

As the FERC stated in Order 888, "Although jurisdictional boundaries may shift as a result of restructuring programs in wholesale and retail markets, we do not believe this will change fundamental state regulatory authorities, including authority to regulate the vast majority of generation asset costs." In the current environment the FERC will likely continue to allow the RTOs to develop their own resource adequacy mechanisms, and then evaluate their just and reasonableness.

### *PJM's Existing Resource Adequacy Model*

PJM, the original power pool, is also the originator of the ICAP mechanism. PJM began setting weekly capacity requirements in 1956, and in 1974 this morphed into an annual requirement with a purchase and sales mechanism and with deficiency penalties similar to today's ICAP model. The current PJM ICAP model has the following characteristics:

- The pool sets an annual Installed Reserve Margin (IRM) a year in advance.
- The IRM is the amount of capacity above the forecasted peak demand that is needed to meet the resource adequacy criteria (115% of peak).
- All LSEs are responsible for meeting their share of the annual IRM.
- A load asset's capacity responsibility is based on its contribution to the previous five coincident peaks.
- Installed Capacity is converted into Unforced Capacity (UCAP), which de-rates units based on historical generation forced outages (EFORd).
- LSEs can use their own assets, contracts and qualifying demand response as ICAP resources. Contracted sources outside of the local control area can also qualify if it can be demonstrated that the power cannot be recalled by another. LSE's can also buy Unforced Capacity Credits (UCCs).<sup>7</sup>
- Three seasonal capacity intervals are defined for capacity commitments.
  - June – September
  - October – December
  - January - May
- Failure to comply with the daily capacity requirement for any reason other than load shift results in the assessment to the LSE of a deficiency penalty of \$171.18/MW-day, multiplied by the entire seasonal capacity period.<sup>8</sup>

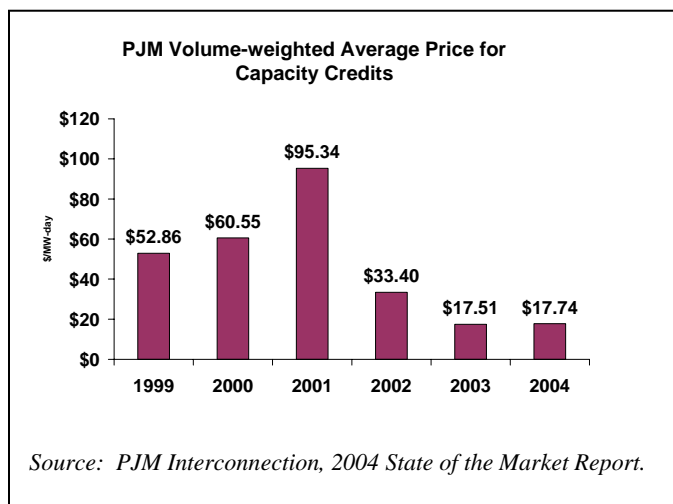
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<sup>7</sup> UCCs can be purchased bilaterally, and PJM facilitates transactions and sets a market price by holding annual, monthly and daily UCAP auctions. A UCC is a tradable UCAP credit, they serve to account for the network resources dedicated to serving pool load.

<sup>8</sup> A charge of \$20,883.96 could be assessed in the summer capacity interval for being short one MW in any day.

In return for ICAP payments, sellers are required to offer their resources into the day-ahead market and coordinate planned outages. In addition, any exports from ICAP resources to other control areas are “recallable” to serve PJM load. To ensure that energy from generation capacity can get to the load, PJM has a deliverability requirement that new generation must add sufficient transmission capacity to be deliverable to the pool before it can qualify as UCAP. **The deliverability requirement has kept the UCCs reasonably fungible across the pool, and the additional supply has pushed prices lower.**

Though supply conditions are currently sufficient to result in a competitive outcome for the capacity markets, the PJM Market Monitoring Unit (PJM MMU) reports “Market power is endemic to the PJM capacity markets.” The ICAP market is prone to the exercise of market power for a couple of reasons. First, in many cases a single party has the potential to influence the clearing price. Second, supply and demand are generally inflexible and well known before the auction, as is the penalty for not procuring credits. The price of ICAP in the daily market can and has cleared at the deficiency rate (the price cap). As PJM has expanded, the clearing prices in the daily ICAP auctions have generally declined on an average basis (see figure above).



Lower prices subsequently called into question the ability of ICAP to provide an incentive to generation developers to provide new capacity resources. Increased calls to change the ICAP mechanism and adopt a demand curve to set the price of the product followed (see description of NYISO demand curve below.)

PJM is concerned that the pool resources will not be deliverable to all zones as load grows and older capacity retires. Therefore, it has recently proposed a new resource adequacy model that would create sub-zones for UCAP in the eastern PJM zones so that more constrained zones would pay higher UCAP charges. This new model goes further to use an administrative price setting mechanism for the UCCs, and requires the purchase of the required capacity four years in advance of delivery. Not only would this provide a longer-term signal for future resource adequacy needs, it would, in theory, allow more contestability in the ICAP market as sellers could bid in speculative capacity. This model, referred to as the PJM Reliability Pricing Model is discussed in more detail on page 15.

### ***NYISO Resource Adequacy Model – The Demand Curve is Born***

The New York Independent System Operator (NYISO) uses an ICAP/UCAP model similar to PJM in most respects. The New York State Reliability Council sets the IRM, currently 118% of peak, and the NYISO determines the Minimum Unforced Capacity Requirement.

LSEs are given installed capacity obligations (tags) based on their share of forecast peak load. The NYISO runs Capacity Period (seasonal), monthly and spot market UCAP auctions. From the beginning, the NYISO resource adequacy model was different from PJM in one important aspect – locational requirements.

Despite an excess of capacity state wide, transmission across the Hudson River into New York City has been considered highly vulnerable, and therefore the city has had a locational capacity requirement (pricing for Zone J). The “in-city” requirement is targeted at ensuring sufficient capacity to meet load



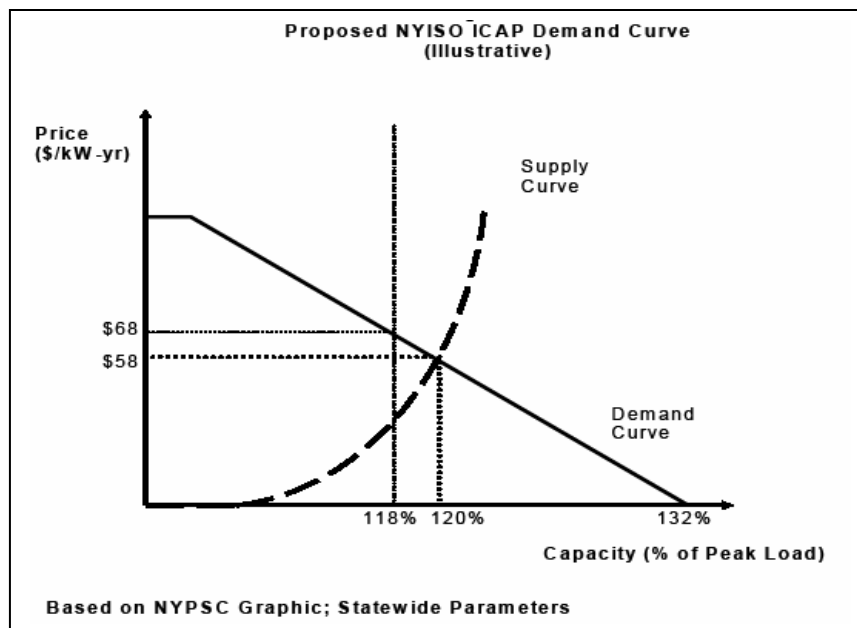
with the loss of upstate resources.<sup>9</sup> The uniqueness of Manhattan, with a dense population and energy-hungry underground facilities (requiring continuous pumping to expel water) increases the value of lost load and therefore the price the population can be assessed to preserve service.

The congested nature of the city also made development of generation and transmission capacity difficult, keeping the reserve margin small. Therefore, when **Consolidated Edison's** generation resources were sold to merchant power companies, pursuant to state regulatory directives,<sup>10</sup> the capacity prices the new owners could charge were capped to "protect" consumers from the exercise of market power.

The locational requirements created a bifurcated ICAP market, with Zone J capacity always clearing near the cap (about \$350/MW-day), and up-state capacity clearing much lower. Capacity is a product that has very **binary value to customers**.

**When customers don't need capacity** (e.g., supply exceeds demand) **they are not willing to pay anything for it. When the market is short, however, capacity that can keep the lights on has infinite value** (or at least will clear at or near the cap price).

The NYISO and the NY Public Service Commission (NY PSC) are concerned that the robust pricing in Zone J sent the wrong incentive to new resources in constrained zones: new capacity would depress the otherwise attractive capacity prices.



To encourage new resources, it was proposed to no longer allow ICAP to clear at its own level of equilibrium, but to have the market clear along an **administratively determined "demand curve."** The ICAP demand curve is like a real demand curve in that it is a combination of quantity and price at all points.

However, it differs from a "real" demand curve in that it is not a function of what consumers are actually willing and able to pay, but **it is instead a function of the expected cost of a new peaking generator (proxy) and a capacity target for reliability set by regulators.** The curve starts at a level where ICAP credits will be valued at 1.5x the cost of a new peaking generator, decreasing along a slope until it prices ICAP at the estimated benchmark cost of new capacity (EBCC), and continues sloping downward until it reaches zero. The flatter the slope the less the price of ICAP will change for each change in capacity quantity.

**The seasonal capacity requirement is defined by the supply offered, not by the supply sought.** This means that if there is 120% of peak load available to the market, customers must pay for ICAP representing 120% of their peak loads even if the NYISO target is only 118%. This has led to a lot of

<sup>9</sup> Long Island is another zone with an internal capacity requirement and limited resources due to transmission constraints and the closing of LILCO's Shoreham Nuclear facility.

<sup>10</sup> Unlike other states, there is no state restructuring law, the NY Public Service Commission has been restructuring the utilities with incentives and creating competition rules by decree.

understandable grumbling from customers and marketers about giveaways to the generation suppliers for capacity capability that will never be used because it's not needed.

The demand curve prices are used in the monthly spot auctions. LSEs are informed of their capacity requirement (from the seasonal stack of supply assembled by the NY ISO). The LSEs must then procure demonstrable capacity either through self-supply, demonstrable demand response, bilateral contracts, or by participating in the seasonal auctions for capacity.

If that doesn't result in enough capacity, the LSE would be required to procure capacity in the monthly spot auction. The LSE would not actually bid into this auction, but would take whatever capacity is required at the price set by the intersection of the available supply stack and the administrative demand curve.

Sellers would have little incentive to discount sales of capacity to LSEs for fixed terms. Given the slow addition of new resources to the New York market, it is not hard for suppliers to make educated guesses as to where the demand curve and supply curves will intersect.

Suppliers will do no worse than the ICAP price in the spot monthly market. After all, load is required to buy all of the capacity available under the price set by the supply stack.

Both utilities and marketers find this proposition very unappealing. Under this regime it is very hard to substantially hedge capacity costs, particularly over a multi-year period. The year-to-year cost of ICAP can also vary as the EBCC changes. EBCC, which sets the starting point of the curve, can be adjusted depending on conditions such as changing assumptions about the interest rates on the cost of capital for the proxy plant.

The expectation of the NY PSC and the NY ISO is that the price stability afforded to suppliers will increase the amount of capacity built in-city and on Long Island. The other claimed benefit of a demand curve is that it decreases the benefit of withdrawing marginal capacity from the market, and therefore reduces any incentive for suppliers to withhold.

While some would say that it is too early to judge the long-term affect on investment, we note that no major investments or retirements have been announced since implementation. The stable ICAP rates are likely to help the NY ISO or specific loads avoid having to sign reliability-must-run contracts (RMR)<sup>11</sup> with older generation units. The ICAP payments at or above the cost of new capacity should continue to offer sufficient revenue to maintain operations at older generators.

### ***ISO-NE Resource Adequacy Model***

The members of New England Power Pool (NEPOOL) and the New England Independent System Operator (ISO-NE) have all struggled to agree upon a resource adequacy mechanism for the past decade. The adequacy planning tool, called Objective Capability (OC), sets a target for pool capacity to serve the pool's peak load, plus a reserve margin to meet a defined level of contingencies. The OC becomes the basis for assessing the installed capability requirement for each LSE in the pool. Each load serving entity

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<sup>11</sup> RMR contracts are out-of-market contractual obligations paid to a facility that otherwise would meet the criteria for retirement but that the grid operator wants to maintain in order to facilitate reliability. These are cost-of-service contracts; however, they are rarely of multi-year duration. They do not provide sufficient revenue streams to fund environmental upgrades (often a reason for retirements) or significant re-powering projects for enhanced efficiency. Many market participants believe that reliance on RMR contracts has many unfavorable market impacts including as a barrier to entry and protecting load that does not resolve its capacity issues from interruption when that load should be supporting new generation or transmission infrastructure projects.

is given a monthly requirement to bring enough ICAP (by owning generation, demonstrating demand response capability or buying a capacity entitlement) to cover its load-weighted share of the pool's OC.

Prior to 1998, when utilities in New England were still vertically integrated, any LSE that was short on capacity (e.g., the capacity they brought to the pool was less than their load-weighted share of the pool OC requirement) would have to pay a deficiency charge. The deficiency charge was set at \$8.75 per kilowatt-month, which represented the estimated avoided cost of building new capacity, plus a penalty. The penalty was rarely imposed because suppliers were vertically integrated. Like PJM, when NEPOOL began the process of creating a deregulated wholesale market for electricity it was decided that the pool would continue the OC process, and require that each LSE continue to procure ICAP.

NEPOOL's economic consultant warned that capacity owners could easily manipulate the ICAP market; he recommended that since it had been manipulated in the past it should be abolished.<sup>12</sup>

For the first twenty months of the market (which began in May 1998) the ICAP market cleared at or near zero. That changed on the January 2000 ICAP settlement, when shifts in supply and demand<sup>13</sup> had the ICAP market clear at \$20,000 per kilowatt-month. The same week the price for ICAP on the bilateral market jumped from \$1.50, where it regularly traded, to \$4.50 per kilowatt-month. **The ISO-NE, determined that there was insufficient competition in the market for ICAP and settled the market at zero for the month effectively making the market irrelevant.**

With the collapse of the bid-based ICAP market in January 2000, the ISO-NE at first agreed that it should be eliminated. It then decided to keep the ICAP requirement, settling on a deficiency rate of \$4.87 but only until it could get FERC approval for the "alternative market based reliability assurance mechanisms" that it proposed at the end of 2001. The Peak Unit Safe Harbor (PUSH) mechanism was one of the proposals to replace ICAP, as was the Forward Reserves Market. Both have been implemented, but the FERC found in 2003 that the PUSH program wasn't working as desired in all parts of the market.

Unlike PJM, NEPOOL does not have a deliverability requirement for capacity. In 1998, the FERC ordered NEPOOL to adopt a "Minimum Interconnection Standard" that does not require new generation resources to expand the grid beyond minimum reliability requirements. Since all generation was considered to be deliverable as ICAP, this situation resulted in generation being built in Maine, unable to be delivered to the load zones in Southern New England. The minimum interconnection standard did not prevent generators from siting at points on the grid that already suffer from congestion and in the end did little to really provide incremental capacity to tight market areas.

Generation owners claimed that because of price mitigation, and low ICAP payments, revenues were insufficient to maintain units. They began to seek retirements that the ISO-NE did not want to grant.

The result of continued load growth and insufficient transmission into congested areas to permit retirements, many of older units were awarded RMR contracts to delay decommissioning. In 2005, the ISO-NE has a total of 18 RMR contracts in Boston and Southwest Connecticut, totaling 3,400 MW of capacity (or just over 10% of the 32,000 MW available in the market). The rapid increase in RMR contracts lead to the ISO-NE to file for adoption of yet another program using the demand curve methodology (Locational Installed Capacity or LICAP), which was approved conceptually by the FERC and awaits final rulings on implementation following a hearing. The LICAP proposal, described on

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<sup>12</sup> *A Review of ISO New England's Proposed Market Rules*, Peter Cramton and Robert Williams, September 9, 1998.

<sup>13</sup> Strange bidding practices occurred when a market participant was believed to have left ICAP out of a contract to supply service to a Connecticut LSE. There would have been an incentive to do so as the market had been clearing at or near zero. It was clear that one or more market participants believed that the supplier was short ICAP and suddenly ICAP bids began inflating up to the dizzying pinnacle of \$20,000/kw-month. While there were no offer caps at the time and no rule against raising the offers, the ISO saw this as market power and nullified the results.

page 14 could significantly increase the cost of ICAP both in Boston and in Southwest Connecticut. There could yet be a significant amount of litigation at the FERC over the program.

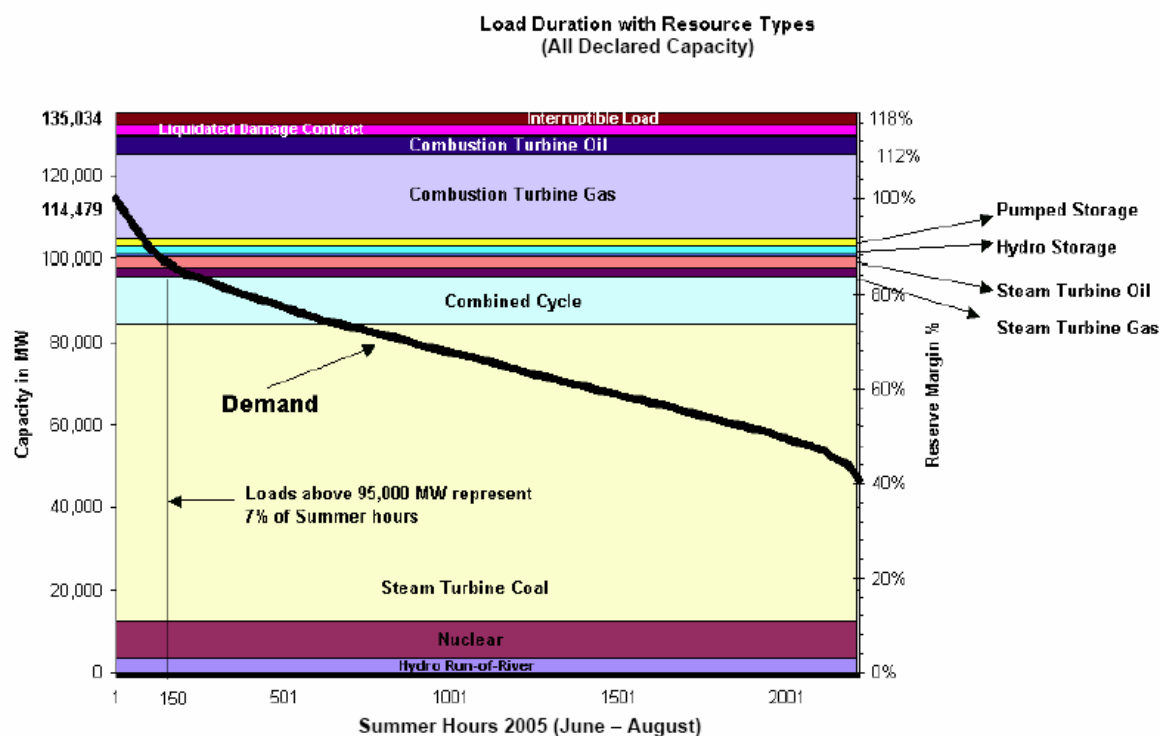
### *MISO Resource Adequacy Model*

The Midwestern ISO (MISO) began operations of its market on April 1, 2005. The MISO market covers multiple reliability organizations (MAIN, MAPP and ECAR), is international, and has both open retail access and vertically integrated states. Despite this diversity, MISO was able to adopt most of the standard market design of centralized dispatch, locational marginal pricing and congestion management used by the Northeast RTOs. What the MISO did not adopt is the same resource adequacy requirement.

The MISO instead adopted a flexible, short-term resource adequacy requirement to accommodate its various regional reliability organizations. The MISO states its intention to terminate these protocols (in Schedule E of the MISO OATT) with the eventual adoption of a long-term resource adequacy plan.

However, developing a comprehensive long-term model will be difficult in an RTO with a mix of reliability rules and commercial interests and the existing resource adequacy rules will likely be extended beyond the current planning year. All LSEs must comply with the existing operating and planning reserves obligations of their RRO. In addition, LSEs must identify to the MISO what specific resources it is relying upon to meet its obligations. Compiling all the reported resources, the MISO estimates that it has 118% of the resources necessary to meet the forecasted load for 2005. The MISO has reported that it has audited the claimed capacity to ensure that none is double-counted.

Unlike the Northeast RTOs, MISO accepts as network resources both contracts with specific units to provide deliverable capacity and also forward contracts for energy [Firm Liquidated Damages Contracts (Firm LD)].<sup>14</sup> Firm LD contracts are not accepted as network resources in the Northeast as the units backing the contracts are not identified until real-time delivery and therefore not dispatchable in the day-ahead market. However, in most commodity markets, a forward contract for delivery with a liquidated damages provision is the norm. The value of a Firm LD contract in long-term resource adequacy is an issue in California. As a growing proportion of load is being served with this type of arrangement, it may



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become necessary for the FERC to set a consistent policy for treating Firm LD contracts for the purpose of long-term resource adequacy.

### ***ERCOT Resource Adequacy Model***

The Electric Reliability Council of Texas (ERCOT) currently has no resource adequacy requirement. Initially, ERCOT had a balanced schedule requirement that did not allow LSEs to rely on the system operator to schedule resources if an LSE mis-forecasted demand. By requiring LSEs to bilaterally contract for supplies including their peak reserve, the Texas model provides for a smaller chance of an LSE being short power and creating a resource adequacy problem.

Later, ERCOT adopted a “relaxed” balance schedule that allowed LSEs to procure more than 20% of their energy on the spot market. However, there are still strong disincentives to under-scheduling as LSEs can be charged for replacement reserves if the system operator has to dispatch additional resources. Exceeding the 20% threshold also exposes an LSE to much higher credit requirements. ERCOT is considering adopting an LMP market similar to the Northeast ISO’s, which would put further pressure on adopting a resource adequacy program if under-scheduling penalties were dropped.

When the market began, the reserve margin in ERCOT was nearly 30%, while the ERCOT board set the minimum reserve margin at 12.5%. In 2001 the Public Utility Commission of Texas (PUCT) adopted a policy direction that it would not impose any resource adequacy requirement until reserves were forecast to fall below 12.5%. In the intervening years approximately 10,000 MW of capacity has retired or has been “mothballed,” pushing the reserve margin down to 17% for 2005. ERCOT now forecasts future capacity below 12.5% by 2010. Subsequently, the PUCT has initiated a rulemaking on resource adequacy<sup>15</sup>, and expects to make a decision this year.

The PUCT is considering ICAP, but ERCOT is different from the Northeast RTOs, and not only because it is not FERC-jurisdictional. As the pool is only minimally interconnected and there are few exports there could be no “recall rights” attached to an ICAP product, and it would have to be defined differently if adopted. Also, because there is no historical pool resource adequacy requirement the PUCT is free to consider all alternatives. In the current proceeding the PUCT has taken comments not only from PJM, but also Australia and Alberta – two “energy-only” markets.

### ***California ISO Resource Adequacy Model***

California in 2000 was a good example of the negative affects (operational, economic and political) of having insufficient resources to reliably serve load. However, it is not necessarily true that if California had a resource adequacy requirement modeled after the Northeast RTOs in place that the result would have been any different. First, those resource adequacy models do not take into account large, systemic externalities, such as the worst drought in several decades. Secondly, ICAP methodology is largely dependent on the resources inside the control area being sufficient to meet the load. California is highly dependent upon imports. The state does not have excess power that it exports but could “recall” if needed.

California has so far managed its resource adequacy problems by using a contractual approach of entering into long-term energy contracts with LD provisions (and getting a little help from the weather.) However, this is not viewed as a long-term resource adequacy solution. The California Public Utility Commission (CPUC) stated it will implement a minimum 15% planning reserve margin requirement by 2006. While the date may slip, at this point all LSEs will be required to acquire 15% - 17%<sup>16</sup> reserves for all months of

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<sup>15</sup> PUCT Project #24255 Rulemaking Concerning Planning Reserve Margin Requirements.

<sup>16</sup> The reason the CPUC has instituted a range of reserves is to discourage California utilities from contracting for more than 17%, as the utilities will be allowed to put their costs in rate base.

the year, and forward purchase 90% of its peak load plus reserves for the summer period (May – September).

The CPUC considered an ICAP approach, but was dissuaded by the number of long-term Firm LD contracts that had been purchased by LSEs, including the California Department of Water Resources on behalf of utilities in the wake of the market meltdown. Disallowing LD contracts for the purpose of implementing ICAP would have required either the renegotiation of contracts, or paying suppliers again for capacity. Yet unresolved in the CPUC's long-term resource adequacy mechanism is how resources will be counted and verified. The CPUC staff and stakeholders are currently developing a "workshop report" on compliance and may recommend that a discount rate (a proxy forced outage rate) be applied to Firm LD contracts to account for the possibility that, like unit contracts, the supplier may fail to deliver.

### *New England LICAP*

The concept of New England's Locational Installed Capacity Market (LICAP) emerged from proceedings that initially began in February 2003 related to four RMR contracts for 1,728 MW of generating capacity in the constrained zone of Southwest Connecticut between **NRG Energy** and the ISO-NE.

In April 2003, the FERC rejected the RMRs and instead directed that NRG track maintenance costs and modified how bidders like NRG could offer their capacity (the Peak Unit Safe Harbor bidding mechanism, or PUSH). What became clear by late 2003, however, was that PUSH wasn't going to work either, and NRG sought to retire the units or restructure their commitments as part of its bankruptcy proceeding. In January 2004, NRG filed new RMR agreements. The FERC accepted the filing of the RMRs and set the costs associated with them for hearing. The RMRs would remain in place until the ISO-NE could adopt its newly proposed LICAP plan, which the FERC subsequently approved, subject to the outcome of hearing procedures on the details. The hearing schedule should permit the new program to be put in place by Jan. 1, 2006 and remove the need for the RMRs.

The administrative law judge (ALJ) who managed the hearing on the LICAP proposal at the FERC released her initial decision on the shape of the demand curve and other technical issues. She substantively upheld the ISO-NE's proposal.<sup>17</sup> We would expect the full commission to make a decision on the ALJ findings this fall, and at this point expect that the LICAP program could indeed be implemented by Jan. 1, 2006.

A separate demand curve will be developed for each designated region in New England and applied uniformly within each region. The demand curve will be adjusted annually and thoroughly reviewed every five years. The EBCC starting point is based on a DCF analysis provided by FERC trial staff.<sup>18</sup>

One aspect of the ISO-NE proposal that is new relative to existing programs is the "peak energy rent adjustment" or the PER. The ISO will forecast revenue (less variable costs) that the benchmark generator would theoretically earn in the energy markets and deduct it from the demand curve price to produce the

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<sup>17</sup> Procedurally, parties to the case now submit briefs if they oppose the conclusions of the ALJ (briefs on exceptions). They then can submit briefs opposing the positions of others (exceptions to exceptions). Only when this briefing period, which closes at the end of July, is completed is the full record available to the commission for review and final decision. It usually takes at least a couple of months for the FERC to rule on an ALJ decision. There is no statutory requirement to act within a certain time period; however, we believe that the FERC will not let this issue languish.

<sup>18</sup> Paragraph 759 of the ALJ's June 15 Initial Decision identifies: Targets the proxy return on equity 12.49%; a return on debt of 6.25% and assumes a capital structure of 57.8% long-term debt and 42.2% equity and an investment grade debt rating.

LICAP payment. But the exact details of how the PER will be applied to ensure there is no double-recovery has been left to a future compliance filing.

The maximum LICAP price at 2 x EBCC is higher than the 1.5 x EBCC used in New York. The NY ISO, however, does not make any deductions from the ICAP price. The PER, however, reduces the LICAP paid from the demand curve value.

The potential to exercise market power is a concern in the LICAP program as well. Therefore the ALJ has recommended the two-step mitigation procedure suggested by **NStar**, one of the LSE intervenors in the case. It is specifically designed to prevent prices from increasing dramatically within New England if exports are made to a neighboring lower-price market in order to tighten supply.

As we mentioned earlier, transmission upgrades are contentious. Another aspect of the LICAP program is the assignment of transfer rights to compensate market participants – either transmission owners, load or customers – that fund specific grid upgrades.

Unlike New York, the LICAP proposal did not receive the support of state regulators. State regulators, consumer advocates and some distribution utilities have argued that the increase in ICAP payments to existing resources is unjustified, and the cost far in excess of RMR payments. It also remains to be seen whether this regime results in incremental additions of capacity to the New England market.

There is also the high probability that any final decision by the FERC could be litigated. However, the commission has done well in the federal appellate system in having its decisions to have installed capacity markets and demand curves upheld. However, some industry watchers think that litigation risk still exists in that the FERC has only approved resource adequacy plans that have had state regulator support. If resource adequacy can still be legally construed as a state responsibility, there may be tension when a program – such as LICAP – doesn't get the endorsement of state regulators and they appeal the approval of a resource adequacy program.

### *PJM's Reliability Pricing Model — A New Approach to Resource Adequacy*

PJM is concerned that the pool resources will not be deliverable to all zones as load grows and older capacity retires. Several retirements are now in the queue at PJM. In 2004, PJM proposed a new resource adequacy model that would create sub-zones for UCAP in the eastern PJM zones – where there are transmission limitations on top of the planned retirements – to allow for higher UCAP prices in these areas.

The most unique aspect of the new model is that it combines the administrative price setting mechanism for the UCCs (a demand curve) with the **purchase of the required capacity four years in advance of delivery**. This advanced procurement requirement is intended to provide a longer-term signal for future resource adequacy needs and identify earlier plants that may be headed for RMR status due to environmental or other considerations. When we recently attended a meeting in New England, skeptics of the pending LICAP proposal indicated it was still unclear to them whether LSEs would really have the responsibility for ensuring adequate capacity or whether it was some other party (the ISO-NE). The nature of requiring contracts instead of just making the overall pool long might be a key driver in attracting new asset construction at more reasonable risk propositions.

PJM would set the capacity requirement for each LSE at 98% of the anticipated demand four years out and then at 24 months there would be an incremental auction to cover any refinements to the forecasts. There is also a separate incremental auction for demand response that did not sign a commitment to an LSE through bilateral negotiations. The demand response auction would take place 3 months before the capacity period in order to best reconcile the interruptible loads' business environment with the market opportunities. Then LSEs would have to procure capacity through self-supply, contracts, and qualified

demand response. If those prove insufficient, PJM will hold a capacity auction for those supplies. PJM would trade this annual market approach for its daily and monthly markets.

The daily market for capacity would no longer be required because capacity requirements would be procured annually. The need for forward procurement is currently outweighing the need for the flexibility afforded by daily capacity markets. Load is not changing suppliers as frequently as forecast when retail choice programs were first implemented. Therefore, annual capacity commitments are not as risky as they seemed a few years ago.

**Unlike the NYISO capacity construct, existing capacity would not simply be totaled up and then billed to load. Instead, load's obligation would be identified well in advance and a solicitation would be made to meet it with a combination of existing and new capacity.** Winners in the capacity auction would be required to provide those resources by either showing that they have the capacity, or have the ability to develop the capacity within 4 years. Given the desirability for contracts to support new additions to capacity, the RPM program would seek to meet this need and facilitate the identification and viability of a revenue stream either through a bilateral contract or an auction award. **We believe that this is a key distinguishing characteristic of the PJM RPM plan that is actually conducive to new construction.** If a unit would be able to furnish capacity, it would also likely be able to provide energy and ancillary services. "Forcing" forward planning and procurement may make prospective purchasers more willing to investigate options to existing capacity resources.

The RPM program, however, has not yet been proposed to the FERC. It has been subject to extensive development and stakeholder meetings, but failed this spring to win majority support from the PJM membership. RPM has also failed to win unqualified support of local state regulators; however, we think that several of the state regulators' concerns can be addressed. The unexpected pushback from stakeholders on the RPM program resulted in PJM management laying aside its plans to have its first capacity auction in Fall 2005.

At this point, it seems that if the RPM proposal is filed at the FERC this summer, it will be difficult to avoid a protracted hearing like the one that the LICAP program endured. It could be well into 2007 before any new program can be adopted.

The probability and duration of a hearing will be directly correlated to how well PJM management manages the concerns voiced by stakeholders. Several parties have criticized PJM for being "unresponsive" to their concerns and a bit of a bunch of "know-it-alls." If this adversarial stance between PJM and its market participants can be moderated and some of the concerns below addressed before the RPM proposal is actually filed at the FERC, the program might be implemented at the beginning of 2007. It is up to the PJM Board of Directors to make the decision whether the RPM plan will be filed at the FERC.

**Some of the concerns regarding the RPM are similar to those voiced in other markets — that it is very expensive insurance and it is not clear that resources will actually be added to the market with this program.** Industrial participants wonder out loud why such payments are needed when they are having trouble managing what they feel are onerous LMP charges (that are paid to generators). We believe, however, that the RPM program at least provides more potential for the participation of new resources through the forward procurement requirement than from the capacity markets that simply give the ISOs or RTOs funds to spend to maintain current market stability.

Other reservations are different from those expressed in other markets. PJM management is considered to be enamored with various market designs and structures. Some are worried that PJM would not let the administrative program atrophy naturally if market conditions improved. At the recent technical conference hosted by the FERC, several market participants voiced a desire for the RPM solution to be temporary or transitional in nature. It is the preference of that group – represented by some LSEs and



some state regulators – that there would be an “exit strategy” to move from the heavily administrative RPM and ICAP approaches toward more energy-only market approaches.

The RPM process has also given a forum to market participants concerned about the viability and efficacy of PJM’s Regional Transmission Expansion Plan (RTEP). The RTEP process is intended to evaluate opportunities to improve the transmission system to accommodate requirements by market participants for firm transmission, load growth, interconnection impact and other “economic” drivers instead of only those improvements that are obvious reliability fixes.

The RTEP process, however, is proceeding slower than many had hoped. A lot of the criticism levied at the RPM program during the June 16 technical conference at the FERC included concern that transmission fixes weren’t being given enough of a role in the resource planning process. While we believe that building transmission is much easier said than done – there is still not sufficient clarity in our view regarding how projects would be recovered if a third party attempted them – it is clearly an area of concern that gives market participants that otherwise like the RPM plan a reason to reserve their enthusiastic support. There seems to be a strong interest in dealing with RTEP concerns within the RPM process. This may not be a welcome tangent for PJM, but might be a worthwhile endeavor if it garners more support for the effort.

**The more issues PJM can either resolve, or at least better explain why they can’t be addressed now as stakeholders desire, the greater the opportunity for a more limited (and hopefully shorter) hearing process at the FERC.**

Some observers note that outgoing Chairman Pat Wood III has had a tendency to set technical matters for litigation hearings at the commission in lieu of technical conferences. Some participants in the LICAP proceeding believe that some of the matters evaluated there might have been better suited to a technical conference between engineering types than protracted jousting between armies of attorneys. A change in approach by the next chairman – whoever that may be – might make the implementation date of an RPM program more feasible sooner.

### ***Environmental Issues***

There has also been growing criticism of the administrative reliability constructs (including the RPM) that they will keep dirty, old and inefficient plants on line. That result is inconsistent with other state and federal goals to retire or retrofit facilities with high emissions levels.

This certainly is a problematic reality that is driven at least in part by the fact that environmental and electricity regulation at the state and federal levels are controlled by different agencies.

A state can – through its own legislation and/or regulation – put conditions on facility permit renewals that can be onerous enough to encourage the retirement of an undesirable asset.<sup>19</sup> Most state and federal environmental programs allow an owner to retire a facility if notice is given. Once that notice is given, the facility is obligated to shut down.

Emissions trading programs can help balance the need to keep dirtier facilities on line for reliability needs; however, some states do not accept emissions credits bought from neighboring states as a policy preference.

However, the local reliability organization can still require that a plant be operated to preserve system integrity. This situation is one driver for the increase in RMR contracts with specific assets. When it comes to environmental upgrades, RMR is clearly not the way to get improvements made, in our view.

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<sup>19</sup> Technically, however, this is still the plant owner’s actual decision.

The RMR contracts are generally short-term in duration as the FERC frowns on them in organized market conditions as they can distort the market. Short-term contracts of a year are clearly insufficient to justify major pollution control upgrades. The costs in RMR contracts are usually based on providing revenue to offset the purchase of emissions credits. However, if emissions credits inflate in price, the RMR operator can bear financial risk.

**In the context of PJM's RPM, however, environmental upgrades may be more likely to occur.** If the energy bill is enacted with the House provisions that would provide accelerated (5-year) depreciation on pollution control investments for plants built after 1970, it could prove a useful complement to the RPM approach. "Dirtier" plants would have the chance to properly cost and bid their assets in to the RPM auction process. If keeping them on line with the desired level of pollution control spending is expensive from the customer perspective, this should provide a market signal for entry of a newer cleaner facility and/or provide incentive to pursue a transmission alternative. It would also give the marketplace a saner, if a bit longer, approach to asset retirement.

### *Conclusions*

Resource Adequacy is a critical part of reliability when demand response is insufficient or non-existent. The inelasticity of demand generally results from the reality that most end-users see average (rather than marginal) prices for peak energy, and because of price caps. The need for price caps can be eliminated by either providing price signals to end-use customers, or by installing excess reserves. To date, most resource adequacy models have been focused on ensuring the installation of reserves. Maintaining excess reserves may be the least-cost solution for end-users when they cannot see or will not otherwise respond to the marginal price. The nature of demand curves and multi-year forward commitments is that they both shift the risk of ensuring against price spikes from investors in suppliers and in utilities back to customers. One of the goals of eliminating IRP was for investors to participate in the risks (and theoretically opportunities) of installing the new technology that would transform the industry.

**A still unanswered question is whether resource adequacy is protection against price spikes or against interruption of load.** The two are substitutes, but one is a private good, while the other is public good (at least until system operators can physically enforce contracts by turning off the lights).

**If resource adequacy is a private good, consumers make their own arrangements via competing market participants and service options.** Regulators can make contractual arrangements for to provide protection for those customers who are unable or unwilling to do so. The greater the responsibility on the customer to manage the volatility he faces, the more opportunity could exist for a variety of market participants to propose different products and services to meet this need.

**If resource adequacy is a public good, then some form of broad regulatory intervention, such as ICAP, is likely to remain a persistent feature of restructured "markets."** However, as we noted in California, an ICAP requirement such as in the Northeast may not be desired and some other methodology needed. Some economic theorists suggest that consumers are better served if resource adequacy is treated as a private good as it will provide incentives for more demand response<sup>20</sup>.

However, system operators and regulators have strong incentives to keep resource adequacy a public good, and the current state of interval metering deployment also argues in favor of regulatory approaches. Advanced metering would make it easier for grid operators to cut off parties who did not contract

<sup>20</sup> For in-depth analysis see *Power System Economics* Part 2, Stoft, IEEE Press, 2002; and "Electric Network Reliability as a Public Good", Kiesling and Giberson, Paper submitted to CMU conference: *Electricity Transmission in Deregulated Markets*

sufficiently for capacity. The current interval metering system makes it nearly impossible for grid operators to discriminate effectively, hence the tendency to “err” on the side of keeping the lights on.

**We consider short-term capacity procurement programs (LICAP and ICAP) as likely to bias positive impacts towards generators already in place. Longer-term (RPM) approaches, in our view, would provide more opportunity for new entry by the next round of assets.**

As current oversupply in various markets erodes over the next few years, we could see price increases in the capacity markets. If new entry is slow, this could result in political problems related to pricing. This is one reason why we have not been intellectually excited about these programs as a driver for growth in terms of assets. We also worry about regulatory backlash putting returns in jeopardy if demand curves result in very high prices.

There are alternative approaches being used in other countries. In Australia, and elsewhere, there is no generation resource adequacy requirement and energy prices are allowed to reach \$10,000 per MW to clear the market. In England and Wales a capacity adder is imputed in the hourly energy price to provide additional compensation to generators who furnish system capacity, but there is otherwise no separate capacity payment. An option-based model for reserves, where LSEs purchase call options, is used in South American pools. As these models all treat reliability as a public good they may suggest more permutations are yet in store for “market-based resource adequacy models” for the United States.

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