REPORT

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PJM Power Providers

Reliability at Stake: PJM's Reliability Pricing Model

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RELIABILITY AT STAKE:
RESOURCE ADEQUACY DESIGNS AND THE SUCCESS OF PJM'S RELIABILITY PRICING MODEL

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1. INTRODUCTION AND SUMMARY

Since 1927, electricity customers throughout the Mid-Atlantic States have been served by the PJM transmission organization, now formally known as PJM Interconnection, L.L.C. Since 1998, PJM has operated not only the physical transmission system but also a set of markets for energy and related products. As PJM's markets have matured, so too has the robustness of the market designs and the range of products traded there. This continuing evolution in PJM's market design is intended to improve price transparency, commercial tractability, and system reliability.

This paper has two primary goals. First, it discusses why capacity markets exist at all and what their role is in providing reliable, cost-effective power to consumers. Second, this paper examines whether the new Reliability Pricing Model (RPM) developed by PJM is performing reasonably. In particular, it rebuts many of the contentions made in a report recently issued by the American Public Power Association and authored by James F. Wilson of LECG, LLC, entitled "Raising the Stakes on Capacity Initiatives: PJM's Reliability Pricing Model (RPM)".[2] Contrary to Wilson's claims, this report concludes:

- Market-based mechanisms that support investment in new resources and retention of needed, economic existing capacity is consistent with both federal and state policies and allocates risk most effectively between consumers and investors;

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2 Available at http://appanet.org/files/PDFs/RPMreport2008.pdf, hereafter "Wilson".

- Among the market-based mechanisms available in theory, in practice centralized capacity markets are superior to either “energy-only” or contract-based designs.
- The PJM RPM design is fundamentally sound;
- RPM provides appropriate incentives to attract new investment, retire uneconomic existing generation, and retain economic existing resources;
- RPM will attract an appropriate mix of resource types, including demand response;
- RPM works with and supports bilateral contracting, including long-term procurements by utilities, states, and other load interests.
- RPM results in prices within the range of reasonableness and is a cost-effective means for achieving resource adequacy in PJM.

PJM has already rebutted many of Wilson’s contentions.[3] In particular, PJM provides direct rebuttal on several key points:

- RPM capacity prices are not the result of market manipulation, and the PJM Market Marketing Unit (MMU) has validated that no withholding has occurred in any RPM auction;
- The RPM market power mitigation mechanism has been effective in ensuring competitive RPM auction results;
- RPM auctions have worked as expected and intended;
- RPM is accurately reflecting the need for new capacity;
- RPM has attracted new capacity and resulted in retention of older capacity that would otherwise have not been available;
- The PJM capacity requirement is fulfilling its role in preserving reliability in accordance with NERC standards;
- RPM auction results accurately reflect supply and demand conditions.

Since PJM has access to much more detailed information about the bids and other information about the RPM auctions already conducted than either CRA or Wilson, this paper

3 *See* http://www.pjm.com/documents/downloads/20080418-pjm-response-to-appa-paper.pdf (hereafter, “PJM Response”. PJM also commissioned a paper written by John Chandley, also of LECG, LLC, “PJM’s Reliability Pricing Mechanism (Why It’s Needed and How it Works)”, released on April 28, 2008, that indirectly rebuts many of the underlying criticisms of RPM made by Wilson. The paper is available at http://www.pjm.com/documents/downloads/pjms-rpm-j-chandley.pdf.

does not attempt to retrace the detailed rebuttal on these points. This paper addresses some of the core market design issues raised by Wilson's report. In particular, Section 2 discusses the issue of whether a centralized capacity market, such as RPM, is appropriate in the PJM market, and what the alternatives might be. Section 3 addresses specific issues Wilson raises regarding his assessment of the RPM mechanism in creating appropriate incentives for achieving resource adequacy, supporting bilateral transactions, and cost-effectiveness.

1.1. Summary of RPM Results to Date

Last year, PJM implemented a new market structure for the "capacity" product. This new market design, RPM, was the result of over 50 stakeholder meetings over the course of five years. This protracted stakeholder process allowed all PJM market participants ample opportunity to help shape the RPM design. Nonetheless, there was not full agreement about the design that PJM ultimately filed with the Federal Energy Regulatory Commission (FERC) in August 2005. Subsequent settlement discussions, however, made sufficient changes to the filed design to lead all but a few parties to drop their objections to the RPM markets.

The RPM design made important corrections to fundamental flaws in how capacity had been bought and sold in PJM.

- Capacity is, by its nature, a long-term product, but PJM capacity had previously been traded daily; in RPM, an annual product is traded on a forward basis, allowing better coordination with transmission planning.
- Since it takes several years to build new capacity resources, RPM moves the primary market-clearing auction to occur three years prior to the delivery year, allowing new entrants to compete on equal terms with incumbents.
- RPM also introduced the concept of locational capacity, to recognize the possibility that transmission limitations may require capacity resources to be secured inside load pockets or additional transmission import capability to be created.
- The older capacity market design was subject to "all or nothing" pricing: either there were sufficient resources available on a day, and prices cleared very low, or there was a deficiency and prices cleared very high. This bimodal pricing provided a very poor economic signal for entry or retirement of resources. RPM buffers price swings by introducing a slightly sloped Variable Resource Requirement, which allows PJM to secure slightly more or less capacity than the target, at somewhat lower or higher prices, respectively. A similar concept has been in successful operation in New York since 2003.

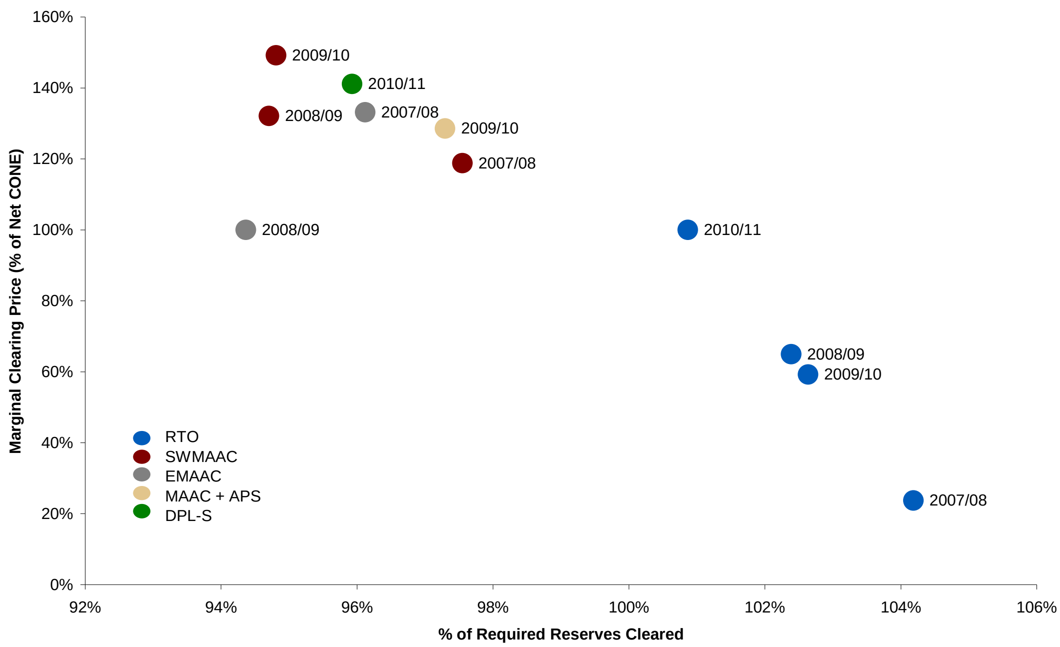
Although the RPM primary auction, the Base Residual Auction (BRA) will, going forward, run three years in advance of each delivery year, PJM has conducted four "transitional" BRAs between April 2007 and January 2008. The results of these auctions—and, more generally, the design and the underlying concepts of RPM—have been called into question by some market participants. As discussed below, however, the results are consistent with market conditions in PJM.

To date, PJM has conducted Base Residual Auctions for four Delivery Years, i.e. twelve months beginning on June 1 of a year:

Base Residual Auction Date	Delivery Year
April 2007	2007/08
July 2007	2008/09
October 2007	2009/10
January 2008	2010/11

Auction results have been in line with expectations, that is, when cleared capacity exceeds the reliability target, prices fall below Net CONE, and vice versa, as show in Figure 1. "Net CONE" is set by PJM, based on engineering costs, financing costs, and an estimate of earnings potential from the energy and ancillary services markets; it is intended to be the capacity payment required by a new, efficient peaking facility. The figure plots the outcome of each auction as a single point, mapping the quantity of capacity cleared in the auction on the x-axis and the clearing price on the y-axis, in each case as a percentage of the target quantity and target price (i.e., Net CONE). All the auctions set an RTO-wide price; in some of the auctions, a locational price was also set for certain of the Locational Delivery Areas defined in the market design, namely Eastern MAAC, Southwest MAAC, MAAC plus APS, and Delmarva South.

Figure 1: Historical Outcomes of RPM Base Residual Auctions



Eastern MAAC increased from a point of only 96% of the Locational Reserve Requirement in 2007/08 to nearly 100% in 2008/09; thereafter, the Eastern MAAC zone did not bind separately. Prices fell between these two years, from 133% of Net CONE down to 100% of Net CONE.

Capacity across the RTO has steadily moved to reduce the amount of surplus capacity, from about 104% of the Installed Reserve Margin (IRM) requirement for the 2007/08 delivery year to 101% of IRM for 2010/11, which is the target for the auction. Consequently, prices have risen from 24% of Net CONE in 2007/08 to 100% of Net CONE in 2010/11.

Although cleared capacity has increased within Southwest MAAC, it did not quite keep pace with increases in the Locational Reserve Requirement between 2007/08 and 2009/10. Consequently prices rose, from 119% of Net CONE to 149% of Net CONE. For the 2010/11 delivery year, SWMAAC did not separate from the RTO, so prices fell to 100% of Net CONE.

There are several possible explanations for why capacity additions did not rise in SWMAAC. One is that non-price barriers to entry, inadequate market design certainty, and the relatively short transition period limited new entry.[4] An additional explanation is that the cost of constructing power plants was much higher than the estimates used to compute the Net CONE underlying the VRR curves and, therefore, prices needed to exceed this administrative estimate by enough to cover the *actual* cost of new entry. We know that the latter case is true; PJM filed substantive testimony documenting increases in (Gross) CONE of about 40 percent; P3 filed evidence indicating a much larger increase in Gross CONE was needed to make new plant construction viable. Because PJM's request to change CONE was dismissed on largely procedural grounds, however, it will be at least one more auction before we can see the effect of a properly set CONE on the efficacy of the auction outcomes.

1.2. SUMMARY OF CRITIQUES

Wilson finds fault with these RPM results. His argument can be summarized in five major headings, each of which has a clear rebuttal:

1. **RPM prices were reasonable and promoted new entry.**

   Wilson reaches many of his flawed conclusions by comparing RPM auction results either to prices in the earlier PJM capacity construct or to simulation results released by PJM. Both are highly flawed comparators.

   As an initial matter, it is deceptive to compare the old capacity prices—which were region-wide price with no locational component—to a weighted zonal average. To the extent the comparison has any validity, old capacity prices must compared only to the RTO RPM price, which also does not reflect any locational constraints. Even such a comparison is meaningless for two reasons. First, the previous capacity construct was found by FERC to be unjust and unreasonable; any comparison of RPM prices to those earlier prices is also unreasonable. Second, one of the particular flaws of the discarded capacity construct is that it exhibited bimodal pricing: even a moderately small surplus resulted in prices near zero, while prices rose rapidly as the pool moved towards shortage. Since PJM overall was in surplus recently, it is hardly surprising that capacity prices were very low, nor should it be surprising under *any* reasonable construct that, as capacity conditions tighten going forward, the prices rise towards the cost of new entry (CONE) net of PJM energy and ancillary services (E&AS) earnings, aka Net CONE. As Chart 1 shows, the RTO RPM prices have remained well below current estimates of Net CONE, consistent with the moderate surplus still remaining in the market through the 2010/11 Delivery Year.

   Wilson's other comparator is the December 2006 RPM simulation distributed by PJM as a discussion aid. Wilson struggles to reconcile these simulations with actual

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4 One non-price barrier may have been that, during the transition period into RPM, potential new entrants were effectively locked out because of how the interconnection queue was administered. Regulatory and stakeholder efforts are underway to address this issue going forward.

market results and, unable to do so completely, attributes the difference to PJM's failings. By contrast, my colleagues and I were able to predict the outcomes of the BRAs with a high degree of accuracy, prior to each BRA, based on extensive research but relying solely on public data and detailed knowledge of the tariff. PJM's simulations were not intended as a forecast, however, but as an illustration. Each slide bears the following note, confirming this:

> "The data reflected herein is provided by PJM solely as a sample of the operation of the Reliability Pricing Model RPM). These results are preliminary and are for illustration purposes only, and do not represent past, current or future actual market data, results or conditions."

No one disputes that the total capacity payments under RPM are substantial; the question is whether they are larger than intended or outside a zone of reasonableness. Using a very conservative replacement cost of $800/kW, the value of the PJM capacity resources exceeds $100 billion; annual depreciation alone likely exceeds $4 billion; this figure includes no allowance for any return on equity or payment of debt costs. In this context, capacity charges of $4.3 billion for the 2007/08 Delivery Year, rising to $8.4 billion for 2010/11, appear reasonable as a 'rental charge' for the fleet, while the approximately $400 million paid in each of 2005 and 2006 appears far too low a fee for reservation of $100 billion worth of productive capital.[5]

Regarding the question of new entry, Wilson's analysis ignores a basic fact—that over 10,000 MW of resources are available to meet PJM's reliability needs today than a year ago—and imbeds a fundamental self-contradiction. On the one hand, he asserts that prices are "excessively high." On the other hand, he notes that "cleared capacity did not keep up with capacity needs."[6] One obvious issue is that RPM is still in the transition period: the BRAs held so far have been run well short of the three-year lead time of the steady-state design. Since developing new projects in less than three years is challenging and costly, it is hardly surprising that new generation offers into the RPM have been scarce; most of the new capacity has been incremental additions to existing facilities or small, demand-side resources. The deeper question of whether the RPM market can attract new entry is discussed below.

2. RPM correctly determines available capacity, need for capacity, and capacity prices.

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5 Generation resources may, of course, also earn net revenues in the energy and ancillary services markets, or from selling renewable energy credits, process steam, and other products. Resources also incur fixed going-forward costs, which partially or potentially fully offset these energy earnings. Studies by PJM's Market Monitoring Unit show that PJM resources have earned substantially less from their product sales than would be needed to support new entry. *See* Table 1.3 of the PJM MMU State of the Market Report for 2007.

6 Wilson at 5.

Wilson states that "RPM's supply curves will understate actual supply primarily because capacity sellers have some flexibility and discretion that result in offering lower quantities of capacity than they actually have available, and at higher prices than their actual avoidable costs."[7] In competitive markets, it should be noted, it is perfectly normal for suppliers to choose both the price and quantity of product they sell. It is only the potential for the exercise of market power that justifies the extensive mitigation of both quantity and price offered in RPM.

Contrary to Wilson's assertions, asset owners have very little flexibility in the quantity of capacity they must offer into the RPM auctions. Owners must offer the full unforced capacity of their resources, based on a five-year average of performance. If a unit has performed unusually well in the past year, the additional capacity created by this anomalously good performance may be offered at a rate reflecting the risk that, in the actual delivery year, the unforced capacity of the unit will have returned to its long-term average, leaving the owner scrambling to find replacement capacity.

Likewise, supplier offer prices in RPM are closely regulated. PJM applies a "three pivotal supplier" test to its markets to determine whether they are competitive. Leaving aside the question of whether this test is appropriate or appropriately applied, by this metric the PJM MMU determined that *every* supply offer in all four BRAs conducted to date would be potentially subject to price mitigation. Whether the mitigation caps are reasonable will be discussed below.

The third point is the erroneous assertion that PJM simply overstates the amount of capacity needed for reliability. PJM has responded directly to this point, noting as well factual errors in Wilson's analysis.[8] Simply put, the decision of how *much* to buy is a fundamentally different question than the best *method* to buy it. RPM should be judged on how well it achieves its targets (among other metrics).

3. **RPM clearing prices properly reflect changes in supply or auction parameters, and includes strong mitigation measures to prevent the exercise of market power.**

Whenever criticisms about any market design are made, it is worth asking, "compared to what?" RPM has an array of market design features that add stability or, at least, predictability, relative to the capacity construct it replaced, including:

- By operating three+ years ahead of the delivery year, RPM allows new entry to compete with existing resources, mitigating potential market power of

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7 Id. at 7.

8 PJM Rebuttal at 5.

incumbents. In economic terms, forward buying flattens the supply curve, damping price movements.

- The Variable Resource Requirement is, in effect, a sloped demand curve, replacing the vertical demand curve of the earlier capacity construct. This change also dampens price volatility and, according to the research conducted by Prof. Hobbs, reduces total costs of achieving resource adequacy.[9]

- Comprehensive bid mitigation. As discussed above, not only does RPM include a must-offer requirement for all installed PJM capacity, the offer price has been subject to mitigation under the rules agreed in settlement and accepted by FERC as just and reasonable.

The fact that these features entail many “administrative parameters and assumptions” should not mask the fact that the only alternative is to do without these features or to shift to some completely different paradigm, but—as discussed in Section 2—other paradigms are less effective, and these price-stabilizing features of RPM are generally viewed as beneficial.

Other forward capacity market designs, such as ISO New England’s, do not include a sloped demand curve, opting instead to rely primarily on the increase in slope of the supply curve created by forward purchasing to produce reasonable results. The trade-off, however, is another layer of rules bounding extreme outcomes. ISO New England’s design, for example, includes a price “collar” for the first three auctions as well as a substantially tighter version of the Minimum Offer Price Rule (to minimize the incentive and ability of *buyers* to suppress prices below competitive levels). Another trade-off may be with total cost: as noted above, there is economic research that indicates that the greater price stability generally associated with a sloped demand curve reduces total consumer costs.

4. RPM’s influence in attracting new resources and retaining older resources is appropriate, and its incentives are aligned with state energy priorities.

In terms of the objectives of attracting and retaining resources and alignment with state priorities, again the question must be asked, “compared to what?” There can be little doubt that the capacity construct replaced by RPM was ineffective in attracting and retaining sufficient generation resources; a primary motivator for implementing RPM promptly was to avert the retirement of key resources in Eastern MAAC. Capacity prices prior to RPM were highly volatile, not locational, and provided no forward visibility for new investment. By contrast, RPM prices are more

9 *PJM Interconnection, L.L.C.,* Docket No. ER05-1410, filed August 31, 2005, Tab H.

stable, locational, and set much further forward in time, to serve as an effective signal for appropriate entry or exit.

As Wilson correctly observes, the range of choices of new resources is broader today than it has ever been, and the complexity of risks created by fuel price volatility, uncertain environmental regulation, and other factors is great. The fundamental questions, then, are how best to make investment decisions under uncertainty, and who should bear the risks of those investment decisions. In a highly regulatory regime, central planners develop a resource plan, develop (through ownership or long-term contract) the preferred resources, and place the full set of costs and risks onto consumers. The alternative is to rely on market forces to sort out investment decisions, placing the risks on investors. The ability of central planning to chart an optimal course in uncertain waters has never been high, and as uncertainty increases, the advantages of relying more on market forces become even more compelling.

Consumers under either arrangement bear costs. In a highly regulated system, however, the full impact of these costs may not be visible for years; indeed, if the regulatory build decisions all pan out well, the scale of risk placed on consumers may never be fully appreciated. But when, as with the last round of nuclear build or with Qualifying Facilities under PURPA, regulated investments prove to be highly uneconomic, consumers are left paying substantial, unanticipated costs. In a market setting, by contrast, consumers may pay a higher capacity charge per MW upfront, but the long-term investment risk is borne by private investors. There are no stranded costs from merchant investment.

RPM, however, provides for *either* approach. Utilities—including public power entities—that prefer to take full responsibility for resource adequacy in their service territory may opt out of the RPM design, using the Fixed Resource Requirement (FRR) option, thereby completely insulating themselves from RPM prices or alleged over-procurement. Even short of a full opt-out, any load-serving entity (LSE) may offer capacity resources into the BRA as self-supply, offsetting its financial obligations in RPM. Indeed, this is why the first auction for each delivery year is called a Base *Residual* Auction: the expectation is that a substantial fraction of load's resource adequacy requirements will have been met prior to the auction through bilateral arrangements or resource ownership.

Consequently, RPM does not stand in the way of any state implementing whatever energy priorities it chooses. States may set renewable portfolio requirements, emissions standards, or other priorities for their jurisdictional LSEs, and those LSEs have the flexibility under FRR or RPM to contract for those preferred resources to meet *both* the state priorities and resource adequacy. Indeed, RPM facilitates achieving all these goals simultaneously by creating transparent prices for the value of capacity. For example, not all renewable energy resources contribute equally to system reliability. If a utility is deciding whether to contract with a lower-cost, lower-reliability renewable resource, or one with higher costs but higher reliability, its decision can be informed by knowing the system value of the enhanced reliability.

5. RPM is cost-effective for consumers.

Once again, we must start with the question, “compared to what?” Wilson’s argument[10] appears to be “to each according to his need, from each according to his ability.” Since not all existing resources require the full capacity payment, they shouldn’t be paid, or at least not as much. By contrast, RPM (and every other capacity market design implemented in the United States) takes the position of “equal pay for equal work.” As discussed later, there is no plausible market structure that can achieve the price discrimination that Wilson advocates; even if there were no centralized market at all, the competition of LSEs to secure resources to meet their capacity obligations under PJM’s Reliability Assurance Agreement will drive the bilateral price for *all* resources—new and existing—up to the alternative cost of buying new resources, when new resources are needed. This is simply the “Law of One Price” in action.

The cost-effectiveness of any sustainable resource adequacy mechanism, therefore, should not be judged by whether it extracts rents from existing generation, but whether it reduces needless risks to investors. As noted above, capacity prices will include a risk premium commensurate with the risks faced by investors in compensation for them taking those risks off the shoulders of consumers. Wilson identifies some improvements to reduce residual risks in RPM; some of these, such as the idea of providing a multi-year price commitment to new generation resources have been implemented in other designs and may prove valuable in RPM. PJM has an ongoing stakeholder process evaluating RPM, and these ideas should be put forward in that forum.

The specter of a complete regulatory overhaul of the resource adequacy mechanism in PJM, however, is an enormous and unnecessary risk facing investors today. Calls for RPM to be scrapped are at best premature; the design has been in place for only a year and there is substantial evidence to believe it is working reasonably well and can, with modest improvements, work even better. Such agitation for a bottoms-up rebuild of a resource adequacy mechanism may be a self-fulfilling prophecy: the risk that calls for fundamental redesign (and, in particular, a redesign intended to penalize existing resources) may freeze investment in PJM until the regulatory environment is stabilized. Having spent nearly a decade debating, developing, and implementing RPM, and given its initial success, it is appropriate to work within the RPM framework, making prudent improvements as warranted, to achieve cost-effective resource adequacy in PJM.

10 Wilson at 82–84.

2. RESOURCE ADEQUACY DESIGNS

At the core of many of Wilson's critiques is an underlying distrust in the fundamental framework of a centralized market to achieve resource adequacy. He fails, however, to provide any other framework. Energy economists have given substantial thought to the question of how long-term investment in energy infrastructure can be supported in competitive markets. Although perhaps some breakthrough idea will supplant existing thinking, the alternatives economists have considered fall into four categories:

1. **Ratebase regulation**: The familiar paradigm in the United States prior to industry restructuring.

2. **Energy-only markets:** Resources rely solely on commodity revenues either from spot markets or bilateral energy contracts. There is no explicit planning reserve margin.

3. **Bilateral reliability markets:** Each LSE is required to secure sufficient resources through ownership or bilateral contracts to meet its share of resource adequacy requirements.

4. **Centralized capacity markets:** A bilateral reliability market is supplemented by a central market in which sufficient resources are secured to meet resource adequacy and costs allocated to LSEs that had not fully met their requirements bilaterally.

This section of the paper discusses the relative merits of the latter three options. (The first option, a return to ratebase regulation, is outside of the purview of PJM or FERC, and its strengths and flaws have been studied in great length elsewhere.) Although there are many criteria that could be applied, these five should be at the top of the list:

1. Does the design achieve resource adequacy?

2. Are the resulting system resources consistent with system operational needs and other policy goals?

3. Are costs reasonable?

4. Are costs allocated equitably?

5. Is the design sustainable, and does it minimize regulatory and other risks?

Answers to these questions frame the following discussion of each alternative resource adequacy mechanism.

2.1. ENERGY-ONLY MARKETS

Admittedly a bit of a misnomer, “energy-only markets” is shorthand for a market design that does not include any mandatory accounting for a planning reserve margin. That is, there is no “capacity” product at all. Instead, spot prices of energy rise high—well above current bid caps of $1000/MWh—when supplies are scarce. These price spikes accomplish two goals. First, following the usual laws of economics, high prices should reduce demand, allowing the electric grid to continue to serve the remaining load. In effect, involuntary load-shedding is replaced by voluntary, price-based load-shedding, to achieve reliability. Second, long-term resource adequacy is fostered by loads and generators each seeking to enter into long-term contracts to reduce the extreme volatility of payments. The level of the planning reserve margin is, therefore, set implicitly by the willingness of customers to pay for lack of service interruptions, rather than by a regulatory body establishing a reserve margin based on engineering standards.

Wilson lays out some of the issues with an energy-only market:[11]

- With relatively few customers ready, willing, and able to respond to real-time prices, there may be little demand reduction even as prices go very high, and the market will have very poor signals as to how much capacity (and reliability) consumers actually seek.

- Allowing price spikes may attract the exercise of market power by generators. If withholding small amounts of capacity in critical hours can move spot prices up by an order of magnitude, the incentives for such withholding would be greatly enhanced requiring a combination of highly effective market monitoring and long-term contracting.

- Price spikes provide an uncertain revenue stream against which to finance new generation. Not only are future supply conditions uncertain, but the frequency of price spikes is strongly dependent on particulars of RTO rules and policies. Consequently, most new investment may require a long-term contract to be financed. Not only does this shift many risks back to consumers, but in areas with competitive retail access, it may be difficult to find a credit-worthy counterparty willing to take on enough contracts to meet true consumer demand for reliability.

Let’s put these issues into the framework of the five criteria set forth above.

2.1.1. Resource Adequacy in Energy-Only Markets

Energy-only markets are intrinsically not designed to achieve some externally established planning reserve margin. In the United States, this raises a serious issue, inasmuch as

11 Wilson at 15–16.

NERC imposes legally enforceable reliability standards on all system operators. Although a planning reserve margin is not, technically, among these requirements, an RTO operating a purely energy-only market may find itself at substantial risk of failing to meet NERC reliability criteria. Indeed, one of the forces motivating PJM's filing of the RPM design was that its engineers forecast reliability criteria violations if some market action was not taken to address retirement of critical units that were not earning enough in the energy market alone to support their going-forward costs.

Even setting this substantial objection aside, there are real concerns as to whether an energy-only market even reaches the resource adequacy consistent with underlying consumer demand. There are several obstacles in achieving even this level:

- Few consumers are exposed to real-time wholesale energy prices and have the ability to respond. Although time-of-use (TOU) metering is spreading, even many of these customers do not also receive a real-time price signal or pay an electric rate directly linked to that price.

- RTO prices are determined *ex post*. If many customers choose to curtail demand because prices are too high, their actions will result in a lower price—quite possibly sufficiently lower that, with the benefit of hindsight, some customers would have preferred to continue buying power. Thus, looking at actual curtailments with *ex post* prices will likely overstate a particular customer's willingness to curtail.

- Effect of retail access. In markets where customers can shift between LSEs, an LSE can gain a short-term competitive advantage by cutting its costs by contracting with fewer suppliers. Such supply contracts imbed a capacity payment, reflecting the risk of future periods with high, spiky energy prices. When such periods occur—and they tend to be cyclical, based on cyclical new unit build patterns—these low-cost LSEs can simply exit the market, having earned their profits during years of relative abundance. The provider of last resort, typically the local electric distribution company, then finds itself with more customers than it had planned or contracted for, leaving the system short of capacity.

- Locational capacity. Nearly all load is charged based on a zonal price, rather than a nodal price. In part, this is driven by the fact that the underlying distribution network draws power from several transmission off-take points, but it also reflects political and practical considerations. Building a new unit to take advantage of a sub-zonal constraint, however, may not be economic. The addition of the new unit is likely to wipe out most of the price spikes that would make that node attractive, but no customer pays the full price of that node, so they have a much diluted incentive to contract with that new unit.

- Biased risk assessments. Customers may not have a fully rational view of the likelihood of high-energy prices in the future. In particular, customers should be willing to pay the *avoided* costs of future price spikes, sponsoring new generation as needed. The resource sufficiency created by those new units, however, will suppress the frequency of future price spikes. Since only *actual* price performance is observed by customers, they will tend to underestimate the future risks of not maintaining resource adequacy. And by the time the actual scarcity occurs, it could be several years before new construction can restore the system to (temporary) balance.

- Risk of after-the-fact repricing. As we observed after the California energy crisis, prices are not always prices, and contracts are not always contracts. Absent a great deal of regulatory and judicial certainty about spot market prices and the sanctity of contracts, suppliers are exposed to the risk of after-the-fact repricing, effectively clawing back margins they expected to earn at the time they entered into investments. Since very high energy prices are front-page issues, the risk of such repricing is materially higher in an energy-only design than in other resource adequacy approaches.

Therefore, an energy-only market structure is likely not only fails to achieve any externally set reliability standards, but it may not even achieve the optimal level of reliability that customers would select in a perfect world.

2.1.2. Consistency of Resource Mix with System and Policy Needs

To the extent that a full set of efficient markets exists to price all of the attributes of generation, the energy-only market design should yield the optimal mix of resources on the system. Compared to a market with price caps, prices will be spikier and, consequently, the system mix will likely shift towards fast-start peakers and units with flexible ramping capabilities, which are best able to ‘chase’ prices up and down.

As a general matter, the optimal mix of resources is driven by the pattern of load over time. If load never varied, then nothing but baseload units would need to be built. Baseload units have high efficiencies and, consequently, lower cost per kWh, but achieve that efficiency through higher capital costs. With varying load, the utilization of marginal units falls and, consequently, the price/performance tradeoff shifts: it becomes more cost-effective to use cheaper generation equipment, even though the production costs per kWh are higher. There are similar economies of optimizing the fleet to reflect the volatility of load, which requires ramping capability carried either on efficient units running at less than full output or on quick-start units. In an optimal market, prices in the energy and ancillary services markets provide correct signals to resource developers as to which classes of units are relatively scarce and results in development of the resources with the greatest earnings potential per dollar of invested capital which, simultaneously, achieves the minimal production cost to meet load.[12]

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12 Loads and load patterns are not static, of course, so developers must forecast future price patterns, and optimality is achieved only to the extent those forecasts are accurate. Under central planning, however, planners must forecast future load patterns, and errors in those forecasts also result in sub-optimal investment. In a competitive market, however, it is the developer who bears much of the cost risk of a poor investment choice, while under a regulated structure, that risk is borne almost entirely by consumers.

In practice, however, there are often gaps in markets. PJM is now, for example, working to enhance its ancillary services markets to provide a better price signal for flexible units. Renewable energy credits (RECs) are not uniformly available, or uniformly defined, so renewable energy sources may not be fully valued. In the absence of complete markets, the fact that energy-only markets do not have any mandatory 'showing' may make enforcement of various resource goals, beyond achieving fundamental resource adequacy, more difficult.

2.1.3. Costs of Energy-Only Markets

In an ideal world, energy-only markets may well be least-cost. But owing to the likely sources of market inefficiencies discussed above, it seems likelier than not that such markets will tend to under-procure capacity, especially capacity needed to solve locational or other problems where consumers do not directly face a price. In this case, energy-only markets are no longer least-cost.

2.1.4. Cost Allocation in Energy-Only Markets

Again, in theory, energy-only markets allocate costs perfectly. Those who want a high degree of reliability pay for it, either by contracting with resources to provide that reliability or by paying very high prices to avoid being curtailed in times of energy scarcity.

The institutional issues created in energy-only markets, however, may create some degree of "free-riding." Under direct retail access, consumers may be able to use strategic switching among LSEs to avoid paying consistently for capacity resources. Likewise, if LSEs can exit (either through a business decision or bankruptcy), they may impose costs on the system.

2.1.5. Sustainability of Energy-Only Markets

A clear-eyed realism suggests that an energy-only market, at least now in the United States, is vulnerable to regulatory interventions. Regulators with 15% reserve margins may be willing to let the chips fall where they may, but if reserve margins fall to 5%, will they be willing to let prices rise, trusting in widespread demand response? If spot prices rise to very high levels for an extended period, will regulators let supply and demand response sort things out? Or will petitions from customers seeking relief lead them to action, even if those customers had ample opportunity to hedge that price risk but failed to do so?

In these situations, it seems more likely than not that the rules get rewritten, and so the regulatory risks facing investors going into an energy-only market are likely much higher than in other markets, at least at this time in most of the United States.

2.2. CONTRACT-BASED RELIABILITY MECHANISMS

The second general form of a reliability market is an approach that relies solely on private contracting to meet a defined target. This design differs from an energy-only design in one critical way: while in an energy-only design contracts are voluntary hedges against potentially high future energy prices, in a contract-based design the minimum level of contracting is specified and enforced by a regulator.

There are several examples of contract-based reliability mechanisms in the United States.

- The California Public Utilities Commission (CPUC) sets planning reserve margins (PRM) for all jurisdictional retail service providers (RSPs) in the state, both overall and locationally. Going into each power year, each RSP must make a showing to the CPUC that it has contracted with sufficient resources to meet its PRM requirements; failure to make a full showing may lead to financial penalties.

- FERC recently approved a new resource adequacy framework for the Midwest ISO, "Module E" of its tariff, that allows each state to set a PRM for its jurisdictional entities while placing the Midwest ISO as the entity that establishes uniform qualification rules, reviews compliance by load-serving entities (LSEs), and enforces performance requirements on all market participants.

- The Mid-Continent Area Power Pool (MAPP) requires its member utilities to carry a uniform PRM as part of its reserves sharing agreement.

In many ways, these bilateral contract-based designs are close cousins to the resource investment paradigm developed under cost-of-service regulation. Historically, vertically integrated utilities developed an integrated resource plan (IRP), agreed with its state commission(s), to plan infrastructure investment—generation, transmission, and distribution—to meet expected future loads. A key difference, however, is that the IRP process was designed primarily to check the incentive for *over*-investment in capital, increasing rate-base and therefore earnings of the utility. In competitive wholesale markets, reliability mechanisms are intended to act as a counter to the risk of *under*-investment in new and existing generation resources. Unsurprisingly, the difference in the functional goals leads to practical differences in how these markets must differ from cost-of-service regulation.

2.2.1. Resource Adequacy in Contract-Based Designs

A core challenge to any contract-based resource adequacy mechanism is jurisdiction. In the United States, this issue has two facets.

The first jurisdictional issue arises on the load side. State commissions do not regulate many of the LSEs in their state. Although the particulars vary from state to state, utility commissions generally do not have authority over municipal utilities, cooperatives, or power agencies of the state or federal government. These entities, however, are interconnected with the same regional bulk power system as the state's utilities and contribute to—or fail to contribute to—the overall system reliability. Moreover, if there are other state policy goals, say, for renewable power, the state's utility commission is often not in a position to enforce these goals on non-jurisdictional LSEs, even if the resource-adequacy contract showing is used to enforce those goals on the jurisdictional LSEs.

Consequently, there is a serious risk that such a contract-based, state-jurisdictional program will either fail to secure sufficient resources to meet state-wide goals, or that the state commission will require the regulated utilities to meet the potential shortfalls directly, with the associated costs recovered either from their bundled customers or through some allocation scheme back to a broader customer base. Under the first outcome, resource insufficiency, the market design has failed in its primary goal. Under the second outcome, mandated utility procurement, a design that was intended to be a more light-handed, market-based system slides back towards a cost-of-service, regulatory outcome.

The second jurisdictional issue arises on the supply side. Under the Federal Power Act, FERC has exclusive jurisdiction over wholesale power markets, including the sale for resale of any "capacity" product. States cannot require an independent power producer to offer its generation for sale, nor to limit at what price that producer can sell its output. Although states can take steps to limit cost exposure from this jurisdictional gap, they cannot simultaneously ensure resource adequacy. In California, for example, an LSE may apply for an exemption from its resource adequacy requirements if it cannot, after a good-faith effort, secure contracts for less than a particular price, previously set by the CPUC. Exactly how any resulting insufficiency in resource contracts would be managed, however, is untested.

To overcome these jurisdictional issues, there must be a level of state and federal cooperation, even when resource adequacy is intended to be met solely through bilateral long-term contracts. FERC has sufficient jurisdictional authority to ensure that all interconnected LSEs fulfill their resource obligations, addressing the first problem. Absent any centralized capacity market, however, it is more difficult to monitor offers from capacity suppliers to ensure that contract capacity prices are in the zone of reasonableness; this problem may be especially acute in import-constrained regions, which often have a higher concentration of suppliers and greater challenges for new, competitive entry.

Even moving past these thorny jurisdictional issues, a contract-based structure has at least two additional major short-comings in achieving resource adequacy. One is achieving the necessary locational mix, addressed in the following section 2.2.2. The second is created by a timing issue.

Simply put, what happens if collectively the LSEs have not contracted for enough capacity? Recall that, under cost-of-service, this was not typically an issue: utilities generally sought out opportunities to invest and prepared plans years in advance to build new generation as needed. The usual contract-based design, however, only requires a resource showing shortly before the beginning of each planning period—or even shorter. PJM took this to an extreme in its now-displaced capacity construct, requiring *daily* showings of capacity. There are very limited options, however, if a capacity deficiency is identified only days or hours before it occurs. The short-run supply of capacity is highly inelastic, i.e., even very high capacity prices will not bring much additional capacity into the market. So, at least in the short run, the pool must simply operate with a resource deficiency.

In a theoretically perfect market, this shortfall would be anticipated—either by LSEs or suppliers—and met by new resources coming available just as needed. In practice, however, the same institutional failures that short-circuit the energy-only model will come into play in this design. Generators will be reluctant to build new generation without a long-term contract, knowing that there is an illiquid market for their capacity. Some LSEs have incentives to contract with less than a full amount of their anticipated resource requirement for a number of reasons: For example, customers may shift, or anticipated load growth may be less than forecast, leaving the LSE with surplus capacity in an illiquid bilateral market. Or high collateral costs and credit risks may make long-term contracting too costly for some LSEs, who instead will rely solely on short-term purchases. In any case, without a multi-year forward showing of capacity, regulators and the grid operator have little assurance of resource adequacy.[13] Although a multi-year forward showing could be required, doing so would impose substantial costs on all LSEs and would likely be beyond the balance sheet strength of many competitive retail suppliers.

2.2.2. Resource Mix in Contract-Based Designs

A resource adequacy mechanism that relies entirely on bilateral contracts (including long-term contracts, as well as shorter-term ones) inherently provides less price transparency than either an energy-only market (with locational energy prices posted by the grid operator) or a centralized capacity market (with locational capacity prices posted by the grid operator). Price transparency serves a critical role in markets, driving investment towards the highest value uses of capital. Since, of the three market-based options, a purely bilateral contracting approach to resource adequacy provides the least price transparency, it is also the weakest in allocating investment dollars prudently. This shortcoming is likely to affect not only resource adequacy overall, as discussed above, but also in obtaining the right mix of resources by location, operating attributes, and environmental impact.

Most grid operators find that locational capacity requirements are necessary in order to maintain overall reliability. PJM's capacity construct prior to RPM did not include any locational requirements, which threatened to lead to retirement of key reliability units in New Jersey because bilateral capacity prices were very low due to a PJM-wide capacity surplus. If, in a contract-based capacity market, LSEs are not held responsible for adding resources in high-cost locations when needed, but are instead allowed to fulfill their resource requirements with generic capacity, there will either be underinvestment in locational capacity or regulators will impose the higher costs of meeting that shortfall on their jurisdictional utilities, perhaps with some cost allocation mechanism. This latter alternative is distinctly a turn away from a competitive wholesale market.

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13 It is worth exploring briefly why this annual demonstration system worked reasonably well in a fully regulated environment. As noted above, in a cost-of-service world, there are strong incentives for the utility to invest additional capital; planning reserve margins not only provided a *minimum* target but also served as *caps* to check the reasonableness of proposed new generation. In some important respects, building new generation added to profits, rather than being a net cost. In a competitive wholesale market, however, the costs of maintaining resource adequacy are, from the perspective of LSEs, at best a pass-through charge. These shifts in profit opportunities also shift incentives to maintain resource adequacy.

In the alternative, imposing a locational requirement in a contract-based resource adequacy market has its share of problems. It further dilutes an already illiquid market, reducing price certainty for investors and purchasers. It may also introduce substantial coordination issues. Load pockets are often fairly small; incremental needs can be addressed in some pockets by the addition of one or two generating units in a given year. If there are two or three (or more) LSEs serving load in that pocket, though, who will step up and contract for the needed capacity? With no clear transfer price by which the LSE that takes on the cost responsibility can sell rights to this more-valuable capacity to the other LSEs, the coordination issue may be a tough nut to crack. Again, it opens the door to a regulatory, rather than market-based, solution, with state commissions taking the lead by ordering utilities to build new generation and allocating the costs to other LSEs. This outcome is not hypothetical; Southern California Edison recently obtained CPUC approval to build very expensive new peaking units near Los Angeles to meet locational reliability needs, with its costs recovered against all loads in the transmission area.

Location is not the only generator attribute that may be under-procured by a contract-only resource adequacy design. Grid operators need flexible units capable of providing ramp and operating reserves, priced in the RTOs' ancillary services markets; policymakers may set standards for emissions or renewable energy content (and markets for emissions permits and renewable energy credits to implement these standards). Lacking price transparency and liquid trading of capacity contracts, however, the incremental market value of capacity resources capable of providing these additional services may not be fully realized, with the likely result that too few of these high-value resources will be procured. These resource attributes also exhibit the lumpiness/coordination issue that we see with locational capacity.

In sum, not only will contract-based designs tend to under-procure resources overall, the resources they are likely to short the most are the ones with highest value to the system: those in load pockets, with desirable environmental attributes, or that provide real-time reliability services.

One benefit of contract-based systems is the direct ability of regulators to implement policy objectives in addition to the basic requirement of resource adequacy. Jurisdictional entities, such as utilities, can simply be told by legislatures or regulators what sort of units to contract with (e.g. renewables) and what sort of units not to contract with (e.g. unscrubbed coal). This benefit is not unique to a contract-only resource adequacy design, however. In both the energy-only markets and centralized capacity markets, long-term and short-term contracts are likely to be the rule, rather than the exception.

2.2.3. Costs of Contract-Based Designs

Proponents of contract-based designs ground their support in the belief that it will save consumers billions of dollars annually.[14] Under this theory, capacity resource owners will sign capacity contracts at their own going-forward costs, net of expected energy earnings. Such an outcome, were it feasible, would indeed lower capacity costs in any given year. Economists refer to this outcome as "first-degree price discrimination," the optimal situation that a monopoly buyer or seller can achieve. There are two glaring flaws in this argument for the apparent cost-savings associated with contract-based designs. In those other market structures, however, contracting can be guided by visible, transparently developed prices for the whole range of services provided by generators, including (in a centralized capacity market) the value of the units' contribution to resource adequacy. Better market prices lead to better contracting decisions.

Foremost, when there are many buyers, they cannot achieve first-degree price discrimination; indeed, they cannot achieve any price discrimination unless they either collude or use a central buyer, e.g. an RTO, to act as the monopsonist on their collective behalf and leave the price discrimination to the RTO. Colluding is, of course, illegal in this country, even among buyers seeking to push prices down. The latter course also appears to be closed: FERC has been petitioned several times to enable price discrimination in capacity markets, and in all three RTOs with capacity markets, FERC has repeatedly rejected such price discrimination as unduly discriminatory. Absent any coordinating mechanism, prices for capacity in bilateral contracts will tend towards a common market price, set by the cost of the marginal capacity resource. Without a centralized market to create price transparency, however, and with relatively low market liquidity to allow price discovery, actual contract prices may be lower *or higher* than an efficient market price.

Another set of costs rarely noted in a contract-based system are the costs associated with the contract itself. Long-term contracts are, no doubt, desirable for project developers since it reduces many risks (particularly as compared to an energy-only market; a well-designed, stable centralized capacity market can offer a high degree of certainty, as well). This guarantee comes with costs to loads, however. Buyers also assume a great deal of market risk that would otherwise be borne by the developer and, at least in many cases, are better managed by the developer than loads. Long-term contracts are treated as debt by ratings agencies, increasing the cost of borrowing for the buyer. Most directly, contracts require (and use up) balance sheet strength, and the longer the contract term, the greater the requirements on the purchaser. Long-term contracts, therefore, may not be an option for smaller retail suppliers, and reduced competition in the retail space may adversely affect both the range and cost of the retail electricity products offered to consumers.

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14 See, e.g., "Pre-Workshop Comments of the Bilateral Trading Group on Resource Adequacy Phase 2, Track 2 Issues," CPUC Rulemaking No. 05-12-013, May 18, 2007, at 11-17.

Proponents of contract-based designs also assert that the administrative costs of this market design are lower than a centralized design. This seems unlikely. Costs in a centralized market are easier to quantify, since all RTOs have public budgets. Costs of a bilateral market, by contrast, are distributed among LSEs, who must have contracting specialists writing and managing capacity contracts and have the burden of making compliance showings (which typically entail load forecasting), and regulators, who must check that each LSE is in compliance and, potentially, take actions if they are not.

2.2.4. Cost Allocation in Contract-Based Designs

To the extent that all contracts are entered into voluntarily, a contract-based resource adequacy design presents no cost allocation issues: consumers pay for those contracts that their LSEs have entered into. As noted in section 2.2.1, though, theory predicts that there will be insufficiently complete contracts to achieve to resource adequacy generally and special characteristics (e.g. locational and operational) in particular. As a practical matter, rather than operating with a deficient system, some out-of-market procurement takes place to fill these gaps. These procurements may take the form of RFPs sponsored by state agency, reliability must-run (RMR) contracts with particular units, or new generation built by or for a utility in ratebase.

There are, of course, direct costs to such out-of-market actions.[15] There is no perfect allocation scheme for these costs, however, or if there is, it is yet to be crafted. Most allocation schemes simply bundle these costs as a non-bypassable charge to all transmission customers, or all transmission customers in a particular zone.[16] Such a scheme provides a positive disincentive for any individual LSE to make an individual contribution to solving the locational or reliability issues directly, through market purchases, since then they will be shouldering not only their direct costs but also the pro rata share of the remaining costs. There are no awards for being a good citizen here. Other allocation systems are based on LSEs' load forecasts with explicit offsets for locational or other special-needs capacity purchased by an LSE going into the year.[17] Such a scheme depends critically on accurate load forecasts and fair assessments of whether the resources purchases in the market are providing comparable services to those procured out-of-market.

In summary, the practical failings of contract-based bilateral designs will likely result in additional, mandated purchases. In turn, the costs of these purchases are imposed on customers in ways that have some degree of inequity and little transparency.

15 There are also indirect costs from bypassing the market, particularly in undermining investor confidence that their new, merchant-based projects will not face subsidized competition.

16 ISO New England uses such a mechanism for allocating RMR costs.

17 The current California resource adequacy system includes a mechanism along these lines.

2.2.5. Sustainability and Regulatory Risks

The variations on contract-based resource adequacy designs that have been tried in the United States so far have not been sustainable. New England, New York, PJM, and California have all tried variations on this theme; in each case, the verdict from investors and regulators has been negative.

One challenge in any contract-based design is figuring out the “or else” to the contracting requirement.[18] The usual answer is to assess deficient LSEs a substantial financial penalty, calculated as a multiple of the estimated cost of new entry. This penalty structure leads to a predictable market reaction: as the date of the resource showing approaches, the market price for capacity contracts either drives towards zero, if there are surplus resources available, or towards the deficiency rate, if there is a resource shortage. This is a knife-edge result (at least if there is full information in the market). To facilitate the transparency of the bilateral contract trading in their pools, the three eastern RTOs operated short-run spot markets for capacity contracts, which merely facilitated contracting by buyers and sellers. Unsurprisingly the prices revealed in these spot markets behaved in this bipolar fashion. The poor price signals have often been cited as contributing to the lack of development of resources to serve load generally in these areas.

The other issue that predictably arose in these pools was the need for substantial out-of-market purchases of specialized capacity. The need for, and high costs of, RMR units was one of the primary drivers for the adoption of forward capacity markets in New England and PJM.

Consequently, although long-term contracts are, in and of themselves, highly stable and provide substantial certainty for the contracting parties, as an overall market structure, contract-based resource adequacy constructs have been unstable and failed to provide sufficient regulatory or financial certainty to meet resource adequacy needs.

2.3. CENTRALIZED CAPACITY MARKETS

Centralized capacity markets supplement bilateral-only reliability markets with several key mechanisms:

- An auction, or sequence of auctions, that brings buyers and sellers of capacity together;
- A central agent (typically the RTO) who acts as purchasing agent, securing sufficient capacity from suppliers;

18 This issue is the primary missing piece of the new Midwest ISO design, remaining under discussion with a filing required by June, 2008.

- A central settlements system, through which all loads are charged and resources are paid;
- A market monitoring unit, to assess the competitiveness of bids and impose mitigation measures as appropriate.

The design of the central auction mechanism itself has evolved. First-generation capacity markets were little more than an enforcement vehicle for the daily capacity requirement of its LSEs; deficient LSEs could purchase any available capacity or they would be assessed a penalty rate. The NYISO was the first U.S. market to employ a "second generation" capacity market, built on an administratively determined demand curve. This demand curve applies only in the final auction before the beginning of each month, in which the NYISO secures capacity to cover any deficient LSE's uncovered position. The sloped demand curve reduced the volatility of capacity prices sharply. It did not go far enough, however, in addressing potential market power concerns, especially in areas with highly concentrated supply and demand such as New York City.

Consequently, all three northeastern RTOs studied alternative design options, in particular those designs in which the initial auction was run far enough in advance of a delivery year that new projects could participate, providing a competitive check on incumbent suppliers and allowing for an orderly replacement of older, uneconomic generation with new resources, when appropriate. Two of these "third generation" designs were approved by FERC in 2006, ISO New England's Forward Capacity Market (FCM) and PJM's RPM. California is also considering a third-generation design as a replacement for its bilateral-only resource adequacy structure. The following discussion focuses primarily on these forward designs, which offer several advantages over older mechanisms.

2.3.1. Resource Adequacy in Centralized Capacity Markets

Centralized capacity markets (CCMs) are the most robust market-based mechanism in achieving comprehensive resource adequacy. Because the market operator acts as agent for load, there can be no issue of some LSEs failing to procure sufficient resources to maintain their share of system adequacy. As long as there are sufficient supply offers with acceptable prices, adequacy can be assured. Moreover, any locational needs can be met through the auction process.

In a forward CCM, like RPM, the market operator has some degree of flexibility that is necessarily absent in a bilateral-only design. Bilateral designs cannot realistically be operated with a full showing many years in advance, since the credit requirements of such contracts would be enormously expensive, likely forcing small competitive retailers out of the market. True shortfalls of capacity in a bilateral design, therefore, may not be spotted until it is too late to take corrective action. In a centralized market, however, the RTOs can commit years forward, and therefore identify any resource deficiencies in a timely fashion. Even if the RTO did not receive sufficient supply offers in the initial auction, it can procure resources through incremental auctions closer to the delivery year.[19] Moreover, the high prices in one auction would encourage developers to propose new developments in the subsequent year's auction, where they would compete to serve the identified need.

Furthermore, all the implemented forward capacity auctions include annual "incremental" or "reconfiguration" auctions. While the primary role of these auctions is to allow capacity suppliers to sell out of a capacity commitment, the RTO may also use these incremental auctions to procure additional resources if needed.[20]

2.3.2. Consistency of Resource Mix with System and Policy Needs

Provided that all resources are paid the same capacity clearing price in each location, capacity markets do not distort the investment decisions among technologies.[21] Competing developers will offer different kinds of resources into the capacity auctions, and the bid will reflect not only the cost of construction and financing, but also the expected net revenues from the sale of energy and ancillary services, as well as whatever other products the resource can produce, such as RECs. In calculating net revenues, developers would naturally consider the expected cost of any plant emissions, so a low- or no-emissions project would have a cost advantage over its more-polluting counterpart, all other things being equal. The winning projects in the auction, therefore, are those that produce the most valuable mix of products (or, more precisely, whose developers *expect* to be the most valuable products). Provided that all products (including emissions) are correctly priced, the resulting portfolio additions are optimal, incorporating all of the information in the market. It should also, therefore, be at least as good as the decisions of a central planner, who by definition has no more (and often less) information than the market.

As with any market-based resource adequacy approach, the optimality of the outcome from a social policy perspective depends on the existence of accurate prices for the various goods (and "bads") produced by capacity resources. Emissions costs are now widely quoted, and the market for RECs is becoming increasingly developed in the eastern U.S. markets. PJM lags some other RTOs in developing integrated ancillary services markets, but PJM has proposed improvements. Overall, therefore, the markets for the most important products are sufficient to support a functioning capacity market.

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19 As a futher backstop, the RPM tariff calls for PJM to conduct a supplemental procurement if the BRA clears short of IRM in two consecutive years.

20 The rules governing RTO purchases differ between RPM and FCM. FCM also allows the RTO to sell back capacity in some situations if its forecast capacity requirement declines.

21 This proposition is demonstrated by several economists, including Dr. Steven Stoft in his Prepared Direct Testimony on Behalf of ISO New England Inc., FERC Docket No. ER03-563-030 (Exhibit ISO-17, filed August 31, 2004) at 87-91.

2.3.3. Costs of Centralized Capacity Markets

Wilson states that "[w]hile the primary goal of [capacity market] mechanisms is to attract new resources, they provide payments to the owners of existing resources, requiring little if any performance for which there are not already strong market incentives, and without any promise that new resources will be built. Thus, with respect to the goal of attracting new capacity, the mechanisms seem expensive."[22]

There are several grave errors in this statement. First, the goal of capacity market mechanisms is to ensure resource adequacy; this may, or may not, be best accomplished by attracting new resources. Consequently, a capacity market must not only attract new resources, when economic, but retain existing resources, again, when economic. Existing resources, too, have going-forward costs and require periodic capital expenditures—sometimes expenditures that approach or exceed the cost of building a new resource. One of the key efficiencies of a well-designed capacity market is to find the balance between retirements and new builds: the market should send the price signals that allow older units to retire when their replacement is more economic than their continued operation (including, necessarily, expected capital expenditures to keep the existing resource performing economically and within regulatory requirements). If existing resources do not receive capacity payments, or receive some discounted capacity payment, then some will retire even when the cost of replacement capacity is greater than the existing resource's avoidable going-forward costs. This is inefficient and expensive.

There is also no practical way to pay only those resources that "need" capacity payments, even if such a system were somehow found not to be unduly discriminatory by FERC. There is a term for such a determination: it is called a "rate case." The prospect of conducting rate cases for every merchant generation facility in PJM should alone be very troubling. Even if this were feasible, however, it would be highly undesirable in a competitive wholesale market. Investment in resources with large capital requirements would be cut off, unless secured by a life-of-unit contract. All new investment understands that it, too, will become an existing unit one day, and its willingness to invest at all, and under what terms, will be driven by its expectations of equitable treatment going forward.

Furthermore, if energy-only markets are the "gold standard" market design (but for the practical implementation issues discussed above) it is worth noting that there is no price discrimination between existing resources and new resources in the energy market, nor between baseload and peaking. If, has often been said, the goal of capacity markets is to approximate the revenues that generators would earn in an ideal energy-only market, that goal would be undermined by price discrimination in capacity markets.

Second, Wilson dismisses without analysis the value of the performance requirements in RPM. The very fact that a resource adequacy mechanism is needed at all tells us that

22 Wilson at 17.

energy price earnings alone are not providing sufficient economic incentives. RPM's Peak-Hour Period Availability Charges and Credits (PHPAC) provide a substantial increase in the economic incentives to be available during the approximately 500 hours of peak system stress each year. Generation owners are taking active—and sometimes costly—measures to improve their units' availability as a direct consequence. Wilson also fails to mention that this performance increase comes at no cost to consumers: the PHPAC *credits* paid to units with better-than-target performance are funded by PHPAC *charges* collected from under-performing units. In fact, consumer costs are reduced by this quest for improved performance: higher unit availability reduces peak-period energy prices and lowers the amount of installed capacity needed to meet resource adequacy standards.

Comparing the costs of centralized capacity markets to bilateral-only markets, there are several factors that should be considered:

1. Efficiency of single-point purchasing. Submitting bids is costly for suppliers, and evaluating bids is costly for purchasers. Creating a centralized market attracts a broader array of bidders, increasing the competitiveness of the procurement. It also reduces bid evaluation costs, since each project needs to be evaluated only once, by the RTO, rather than by each potential buyer.

2. Credit support costs. Long-term contracts to purchase capacity are treated equivalently to a debt issuance by rating agencies and, consequently, raise the cost of borrowing by LSEs. Capacity commitments by RTOs, however, do not have any credit costs, because the payments are guaranteed under the Filed Rate Doctrine against future payments by the RTO's loads.

3. Counterparty risk. The flip side of credit support costs is, for the seller of capacity, the counterparty risk. Again, because the RTO relies collects capacity payments from loads, the counterparty risk for selling capacity into a centralized capacity auction is essentially non-existent. Direct sales to an LSE, however, will have some degree of counterparty risk and, for small LSEs, potentially create a very large risk.

4. Efficiency of managing "lumpy" investments. Capacity resources are not individual, 1 MW blocks. If an LSE needs 42.4 MW of local capacity and 68.3 MW of generic capacity to meet its resource adequacy requirements, it is unlikely to find an exact match with suppliers' available capacity. Consequently, LSEs will likely end up buying from many different suppliers, and any one unit may have portions sold to many different LSEs. In a centralized market, however, the suppliers simply sell to the market, and buyers buy from the market, substantially simplifying settlements and contracting issues.

5. Bilaterals remain an option. To the extent that LSEs find that bilateral contracting is a superior option for them, compared to buying capacity through the centralized capacity market, they can do so and then use the capacity as self-supply in the CCM. Since bilateral contracting remains an option, adding the option of relying on the CCM logically lowers the potential cost of achieving resource adequacy.

2.3.4. Cost Allocation in Centralized Capacity Markets

One of the strongest benefits of a CCM is the equitable cost allocation. After each month, the CCM operator pays all capacity resources (based on performance) and collects these payments *pro rata* from load, accounting for locational prices as appropriate. There is no need to assess whether each LSE has complied with its resource adequacy obligation. By contrast, in a bilateral-only design, LSEs need to forecast their monthly loads accurately; if they over-forecast, then they have may end up paying for surplus resources, while if they underforecast, they risk paying penalties.

In markets with direct access, centralized capacity markets make customer switching completely seamless. LSEs are charged for *realized* load—if a customer switches away from the LSE, its capacity costs migrates away with the customer. In a bilateral market, however, the LSE is left holding surplus capacity contracts, while the customer's new LSE is deficient. The secondary market for spot capacity contracts may not be particularly liquid however, creating risks of losses to either LSE from customer migration.

2.3.5. Sustainability of Centralized Capacity Markets

Compared to energy-only markets, which are politically unviable in most parts of the country, and bilateral-only markets, which have failed to produce market-based investment in every U.S. market where they have been used, well-designed centralized capacity markets have been fairly durable. Moreover, there is no reason to believe that they are not sustainable going forward.

This sustainability creates tangible benefits for consumers. If a resource adequacy construct were unstable or to invite frequent out-of-market intervention by regulators, many investors would simply look elsewhere to invest or require a significant premium. Lenders may require higher interest on debt or simply not lend, forcing projects to be financed solely by equity (which carries a higher rate-of-return requirement than the interest rate on debt). Stable capacity market designs facilitate new entry at reasonable costs—as has been amply demonstrated by the extraordinary amount of new capacity bidding in the New England Forward Capacity Auctions. Although RPM has not attracted the same level of interest, issues with the interconnection queue and the knowably low Gross CONE values baked into the VRR curve are likely the principal culprits. Exelon has recently announced its intentions to build a large combined-cycle facility in Pennsylvania. The accompanying press release states:

> The Reliability Pricing Model policy adopted by PJM and approved by the Federal Energy Regulatory Commission is designed to provide the transparent price signals we need in order to pursue a new power plant.[23]

23 Exelon press release, May 1, 2008.

2.3.6. Other Critiques

Wilson raises a range of generic critiques of centralized capacity markets:

- "The primary obstacles to development of new capacity … are not a lack of financial incentives, but environmental and regulatory approvals, local opposition, etc. To the extent this is the case, the financial incentives provided by capacity mechanisms may be costly while not contributing substantially to overcoming the main obstacles…."[24]

  It is unclear what Wilson proposes should be done in this case; even ratebased generation must receive all its permits and negotiate with local governments. It is, however, naïve to believe that strong financial incentives cannot overcome commercial development hurdles. Not only do high capacity prices lead developers to find creative ways to work with jurisdictional authorities to make projects happen, the high prices also force regulators to take a hard look at what inefficiencies in their approvals process are causing the development bottlenecks and solving them. For example, New York State developed an "Article X" process to streamline the approvals process sequence faced by new developers (a process that, unfortunately, has lapsed).

- "The mechanisms are highly administrative, with many administratively set parameters that can have a large impact on capacity prices and costs."[25]

  Again, the question must be posed, "compared to what?" The RPM design is much simpler than, for example, the three-tiered mesh of regulatory proceedings and showings used in California's bilateral market, and also simpler than conducting extensive rate cases for every merchant power plant in PJM. The RPM design is no more complex than it needs to be; each piece of the mechanism was designed to meet a particular and valid need of the system. While there is room for improvement, RPM, if complex, is not unduly complex.

  Moreover, this concern is excessively focused on the short-run. On average over time, RPM is well designed to clear the market based on competitive bids from new resources. The particular value of administrative Net CONE or other parameters has a small impact on this long-run outcome. While the details are important, they are less so than Wilson implies.

- "The mechanism is highly complex. Experience shows that complex, RTO-run mechanisms can have a wide array of unintended consequences that are often costly for consumers."

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24 Wilson at 17.

25 Id.

While there is a certain virtue in simplicity, the goal should be that no design have needless complexity. Thinking back to the period before the adoption of Locational Marginal Pricing (which was then arguably the most complex design market implemented), PJM has direct experience with how an overly *simple* market design can harm consumers—and grid reliability—as much or more than a complex design. By failing to have accurate locational pricing for each generator, PJM found itself having to declare min-gen emergencies to back down generation that was responding to inapt market incentives. Wilson does not point to any element of RPM that is needlessly complex; indeed, some of his suggestions add a layer of complexity that the RPM Settlement conferees were unwilling to attempt at the time. Moreover, market participants are already up the learning curve on the particular complexities of this design; discarding RPM in favor of another alternative of potentially equal complexity only forces a lot of re-learning (and incurs new expenses in developing software and systems to implement an alternative design).

- "Experience and theory also show that these mechanisms are highly susceptible to exercises of market power (physical or economic withholding) to raise capacity prices. Provisions to mitigate this market power are difficult to devise and limited in their effectiveness."

  Again, compared to what? Wilson acknowledges that an energy-only market is prone to the exercise of market power; bilateral-only capacity constructs have no practical means of implementing market power mitigation at all. Centralized capacity markets allow for extensive market monitoring and, as needed, mitigation; the results are transparent and subject to review by federal and state commissions; and any participant found guilty of attempting to manipulate market outcomes is subject to fines of up to $1 million per day under FERC's new civil penalty authority.

- "Capacity incentive mechanisms are also considered by many a step back from the goal of lightly regulated, highly competitive markets toward more regulated and administered markets, shifting risks back to consumers."

  The benchmark for when an industry is truly competitive is when new entry can be sustained without long-term contracts. Contracts shift risk from investors to customers. Under ratebase regulation, the contract is implicit: projects prudently entered into that are used and useful get full cost recovery, including return on capital. In an energy-only market, Wilson acknowledges that the revenue streams, especially for peaking units, are highly risky, and so such projects would almost certainly need a long-term contract with load, again, shifting much of the risk back to consumers. In a capacity regime where bilateral contracts or ownership is required, contracts once again dominate the landscape. The only resource adequacy mechanism that does *not* require extensive long-term contracts between loads and suppliers is the centralized capacity market design.

3. ASSESSMENT OF RPM MECHANISM

Wilson devotes a substantial portion of his report to an assessment of the RPM mechanism. RPM is surely not perfect, and so a careful assessment and recommendations for improvement are valuable input to the on-going stakeholder review. Some of Wilson's assessments, however, miss the mark and, in particular, fail to offer any meaningful alternative. This section reviews key assessments of Wilson, grouped into three sections: assessments of incentives for resource adequacy, effects on bilateral markets, and cost-effectiveness.

3.1. INCENTIVES FOR RESOURCE ADEQUACY

3.1.1. RPM Pricing Mechanics

Wilson begins his critique of the RPM mechanism by noting that the "RPM price will not accurately signal the state of the system and need for new capacity if the amount of capacity offered into RPM is less than the amount actually available to the system at each price level…"[26] He goes on to note that "RPM auction clearing prices are highly sensitive to small changes in the RPM supply and VRR curves, and to the various parameters and assumptions behind them."[27] By way of example, he includes Figure 14, reproduced below with a slight addition.

In this version of Wilson's Figure 14, I have added a vertical line through point A (shown in red). Under PJM's previous capacity construct, which secured a fixed quantity of capacity, regardless of price, this line would have been the "demand curve," not the VRR curve shown in Figure 14. In Wilson's hypothetical, the result of withholding shifting the supply curve leftward and upward is to raise the price from approximately $165/MW-day to approximately $180/MW-day. But for the VRR curve, though, prices would have rise to point C, or about $240/MW-day. Furthermore, because at point B less capacity is purchased than at point C, the total cost impact is further mitigated.

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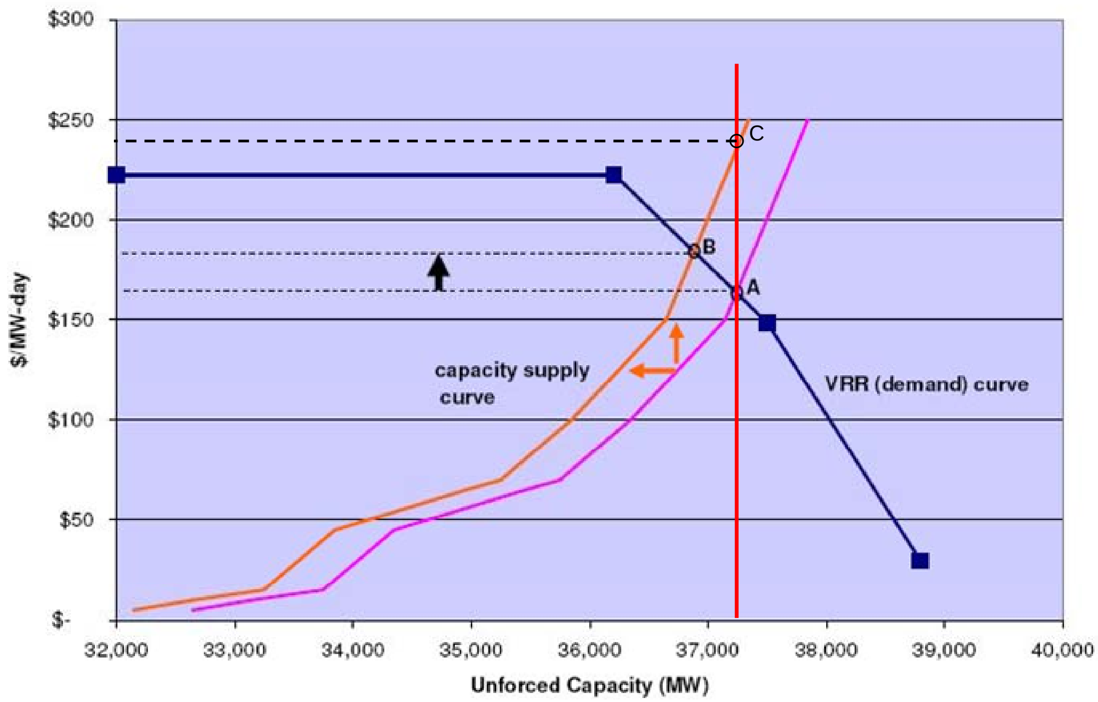
26 Wilson at 54.

27 Wilson at 55.

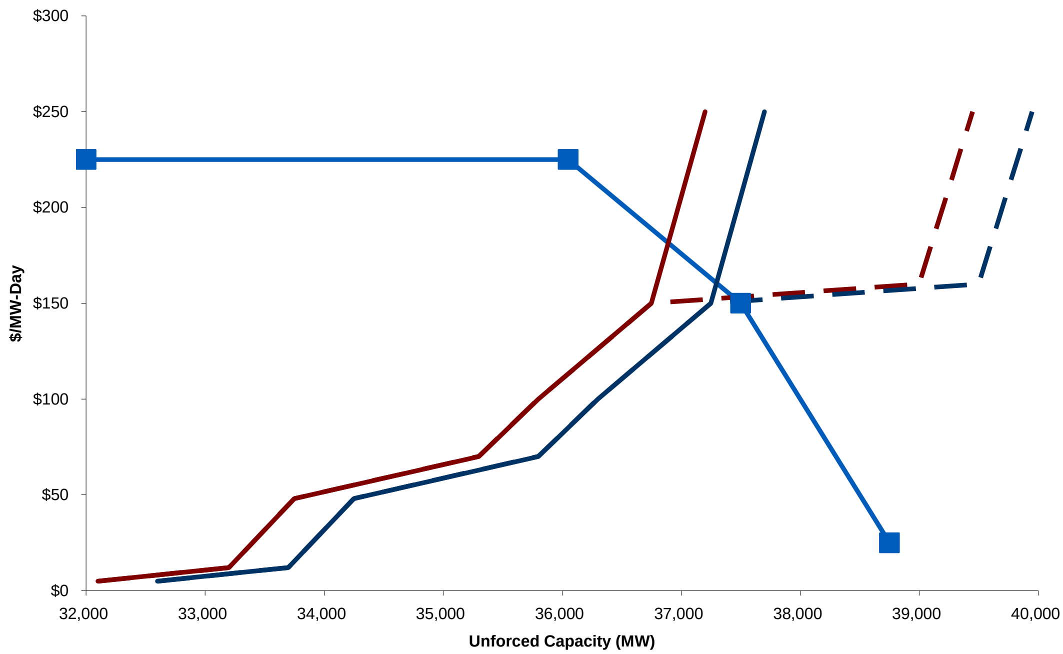
Figure 14: Impact of Lower Quantity/Higher Prices in Offered Supply



This example clearly demonstrates the beneficial effect of the VRR curve not only in reducing the *consumer cost* that that withholding could create, but also in reducing the *incentive* for generation owners to withhold capacity. The leftward shift of the supply curve is about 500 MW. If this hypothetical withholding achieves only a $15 price increase, from A to B, the supplier would need to have about a 6,000 MW portfolio for this to be a profitable strategy. If prices were instead to rise by $75, from A to C, a 1,600 MW portfolio would suffice. In either case, though, RPM supply mitigation rules outright prohibit such physical withholding and would readily detect and reverse the economic withholding.

The stylized supply curves of Figure 14 are not, however, the shape that we expect to see in the steady-state BRAs. The transitional BRAs were conducted with a fairly short lead time before the delivery year, ranging from less than two months up to about two years. As Wilson notes, this is not sufficient time for new resources to be offered, unless they were already far along in the development process. Once new entry can participate, however, the supply curve radically changes shape. We observed in ISO New England's first Forward Capacity Auction that in excess of 10,000 MW of new resources were offered, a remarkable quantity in a pool that needs only about 32,000 MW of total resources. Introducing new entry into the market adds a long, fairly flat segment to the supply curves, as shown in Figure 14A, below.

Figure 14a: BRA with New Entry Offers



With new resources contesting for entry into the market, the hypothetical withholding has almost no effect on consumer costs. With the competitive supply curve (magenta), about 350 MW of new capacity enters, lowering prices to Net CONE ($150 in this example) and increasing quantity out to the target. If a supplier withholds 500 MW of economic existing capacity, it is simply replaced from the large pool of new development. The clearing price rises only by the difference between the cost of the cheapest 350 MW and the cost of the next cheapest 500 MW, which is likely small and uncertain. Both the likely small size and the uncertainty of effect strongly diminish the incentive for any incumbent to withhold capacity.

Wilson expresses concern that many RPM parameters are developed in ways that are not transparent and appear to be error prone. On this matter, we concur. This lack of transparency is an issue, especially as it relates to CETO/CETL calculations. Generation developers face substantial uncertainty in deciding whether to build inside an import-constrained area. Without greater clarity of whether these constraints are likely to persist in the future, developers will not have enough information to know whether it is worth the investment to engage in the advanced development work needed to make a supply offer into a BRA. Wilson likely overstates the immediate impact of such variation, however, since in steady state, each BRA will be clearing on the long, flat section of the supply curve created by competing offers from new capacity additions; therefore, variations in the VRR curve will primarily affect the quantity cleared—which affects generation owners primarily—rather than price.

3.1.2. Offer Requirements and Bid Caps for Existing Resources

Wilson asserts throughout his report that RPM "afford capacity sellers various types of flexibility in the quantities and prices they may offer."[28] This is true, but this "flexibility" is, contrary to Wilson's claims, entirely in line with the sound economics; moreover, FERC has determined that these limitations on supply offers are just and reasonable. Wilson acknowledges that "[p]rovisions providing flexibility in offering resources have merit, as owners should not be required to offer capacity that may not be available, or to offer capacity at prices that may be less than the avoidable or opportunity cost…."[29] Wilson asserts, however, that "the use of these provisions generally cannot be limited to only those circumstances when they are legitimately needed."[30] Wilson details those places in the tariff that create this "flexibility," but fails to explain why any one is anything other than entirely reasonable. Indeed, each was crafted to address an entirely legitimate commercial issue.

Wilson also asserts that the tariff includes provisions that "can cause some capacity that is likely to be available to the market not to be included in RPM." Delays in PJM's processing of interconnection requests are clearly beyond the control of suppliers. Wilson appears to have simply misunderstood the application of Attachment DD § 6.7(d)(ii), which does not provide any exclusion for offering capacity. Likewise, Wilson fails to explain how the FRR provisions can be used to increase prices; after all, the FRR entity has removed itself from the market and has no commercial interest in the RPM price. The report also fails to discuss the importance of the limitation on sales of FRR capacity into RPM in ensuring that FRR entities do not shift costs unreasonably onto other PJM LSEs.

In short, although the PJM tariff does create certain narrow exceptions to the must-offer rule, each of these is carefully crafted to meet a commercial reality and is subject to review by the PJM MMU and, ultimately, by FERC. Wilson has not claimed that any of the cited tariff provisions is unreasonable, for in fact none are.

On the offer cap from existing resources, Wilson asserts that there are "two areas where the RPM rules allow significant deviations from the intended avoidable cost concept."[31] They are the inclusion of capital investments in avoidable cost offer caps and the use of historical, rather than prospective, energy and ancillary services offsets.

Wilson markedly overstates his case by asserting that the "intended" offer price from all existing resources is its avoidable cost. Offer prices should be consistent with competitive levels, but the competitive level is not the same when considering sunk investments versus

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28 Wilson at 59.

29 Id. at 60.

30 Id.

31 Wilson at 63.

prospective investments. An existing resource that requires a substantial investment to meet statutory requirements, however, straddles an awkward space. If the resource owner does not have a reasonable prospect of earning recovery on and of the investment, retirement may be the most economic option, even if that investment is more cost-effective for consumers that building new generation. Large new generators in relatively small zones can bid above avoidable costs past the first year, thereby allowing them to set prices and have a reasonable opportunity to secure some return on investment, at least for three years. The project investment provisions provide a similar opportunity for existing resources to have a reasonable opportunity over several years to earn some return on and of major capital expenditures required for continued operation. Prospectively, this is reasonable and efficient; furthermore, because there is no *guarantee* of cost recovery, only a reasonable *opportunity* to do so, the investment risks are still largely borne by the resource owner. After the investment is sunk, however, a rule that mitigated the resource's bid to its avoidable cost rate—with no allowance made to reflect the project investment—could result in RPM prices below a level that affords the supplier an opportunity to earn a reasonable rate of return on its incremental investment. So, without some rule allowing project investment to modify the mitigated offer cap, the resource owner might not have made the investment in the first place and retire, driving up capacity *and* energy prices for consumers. This section of the tariff was very carefully crafted among the settlement participants and reflects a careful balance of interests judged to be reasonable by FERC.

The other "deviation" Wilson cites is the use of a three-year historical average in computing the E&AS offset. Rather than what, however, Wilson does not say. As he notes, any measure of future expected E&AS earnings based on historical data will have error; it need not, however, have bias. Intervenors in the RPM proceedings sought an E&AS offset based on the single most-recent year of data, a concept that FERC rejected, noting that "that the better predictor of prices in any one delivery year, three years forward, is likely to be a multi-year average price rather than the average price in any single year. Moreover, while JP Morgan expresses concern that historic energy and fuel prices will always understate revenues in the present, evidence in the record suggests otherwise.[32] Wilson infers a trend in the data and implicitly assumes that the higher E&AS earnings in 2007 will persist through another three or four years, rather than reverting towards the mean.

He may be right; he may be wrong. The issue is that neither he nor anyone else knows. But as a general matter, year-to-year fluctuations in peakers' earnings may be driven more by factors of weather, unit outages, and other non-recurring events, relative to structural factors, such as shifts in relative fuel prices or the ratio of baseload units to load. Consequently, using several years of E&AS data is more likely to produce a reliable estimate of future E&AS earnings than a single year. Had 2007 been a particularly *bad* year for E&AS, it seems unlikely that Wilson would be advocating *increasing* the Net CONE; proposing a shift in the metric to be based on a particularly *good* year is no more reasonable.

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32 PJM Interconnection, L.L.C., 117 FERC ¶ 61,331, at PP 118-119 (2006).

If instead Wilson is advocating using some sort of modeled future E&AS earnings to set Net CONE, rather than an estimate based on historical data, he is adding a substantial layer of complexity to the RPM design. The Net CONE estimates used by the NYISO, in fact, attempt such a forecast using a complex, probabilistic modeling technique. The outcomes, needless to say, are highly dependent on the numerous modeling parameters required in such a simulation and are hotly debated each time the NYISO CONE is reset.

Wilson overstates the importance of having the administrative estimate of Net CONE set perfectly because he omits to consider the effect of competitive new entry on the auction. As shown in Figure 14A above, once new entry is needed, the RPM clearing price is set by the offer prices of new entrants—which will almost surely differ from the administrative estimate.[33] If the parametric Net CONE is somewhat too high, the BRA will clear some amount of resources more than it should, but the increase in capacity prices should be negligible. For example, if Net CONE is *twenty percent* above the true capacity price needed by new resources, the BRA will clear *one percent* more resources than targeted, raising consumer costs by only about one percent, not twenty percent, and an associated increase in reliability and a potential decrease in future energy prices. If Net CONE is set too low, however, the BRA will clear fewer resources than targeted, potentially risking reliability in the future. If Net CONE is set much too low, the BRA cap price may be below the true cost of new entry and so *no* new market-based resources would enter. Therefore, the true Net CONE, not the estimate of Net CONE used to construct the VRR curve, will set the clearing price in RPM; but if the Net CONE estimate is set too low, both reliability and the market construct itself could be jeopardized.

Another potential “fix” to this Net CONE estimation issue raised by Wilson is to apply some after-the-fact clawback of energy rents from capacity resources, based on the deemed earnings of some benchmark unit. The ISO New England FCM includes such a provision. This option is both incomplete and potentially undesirable:

- Such a clawback requires more modeling and more modeling assumptions in the market design, adding complexity and uncertainty.
- The FCM clawback is based on real-time prices, but nearly all resources are paid day-ahead prices (or contract prices). Therefore, many resources are forced to make rebates of money they never received.[34]

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33 Note that the NYISO capacity market operates monthly, so new entry cannot be relied on to set the clearing price through competitive offers. The importance of getting the administrative estimate of Net CONE correct in New York, therefore, has more economic consequences than it does in PJM.

34 In theory, day-ahead prices will systematically include a risk premium that the real-time prices will spike, and so the total earnings over time should be equal in the day-ahead and real-time markets. In practice, this may not occur; virtual bids may not fully arbitrage the market, and, regardless, the premium will be spread out over many day-ahead hours, and all resources will not be operating in all the hours when that premium is supposed to be earned.

- The clawback will raise capacity prices. New entrants will include a premium in their competitive bids to account for the expected future cost of these clawbacks and, most likely, a significant risk premium.

- The FCM clawback has many characteristics of an energy call option; it is, in effect, duplicating an energy product that any LSE can purchase through PJM's robust and liquid energy markets. Mandating that all LSEs *also* implicitly purchase this extra call option second-guesses an LSE's preferred hedging strategy and imposes needless extra costs on LSEs.

3.1.3. Participation of New Resources

Wilson avers that offers from new resources "will be close to their own project's levelized cost (which may be very different from a combustion turbine's net CONE) only by coincidence…."[35] This statement is wrong at two levels.

First, there is very sound economic theory as to why all economic resources will have very similar Net CONE values. Suppose, for a simple example, that there were only two kinds of units: baseload and peakers. If baseload units had systematically lower Net CONE values, it must be the case that their E&AS earnings are offsetting a larger portion of their capital costs than it is for peakers. Baseload units would therefore out-compete peakers in the BRA, and the mix of resources on the system would shift towards baseload. In so doing, though, the E&AS earnings of baseload units would decline, while those of peakers would increase, reflecting the relative abundance of the former and scarcity of the latter. Eventually the mix of resources is such that the differentials in E&AS earnings between baseload and peaker units exactly offset the capital cost differences, and their Net CONE values are equal. So, any deviation of Net Cone values of one unit class from another is corrected by the resulting shift in the fleet mix. Using the Net CONE value for a peaker is therefore a reasonable proxy for the Net CONE of any efficient technology (and more reliably estimated, since the most difficult portion to estimate—the future E&AS earnings—is small relative to the capital costs).

Second, the strategic analysis Wilson lays out is deeply flawed.

- The discussion of the optimal bidding strategy for an incumbent implicitly assumes that the incumbent faces no competition. No RPM zones are so small that incumbents have control over all reasonable generation sites, so the incumbent must assume that it has no ability to withhold new entry in the market. The threat of entry, even if there is no actual entry, disciplines the offer price of the incumbent.[36]

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35 Wilson at 67.

36 William J. Baumol, John C. Panzar, & Robert D. Willig (1982). *Contestable Markets and the Theory of Industry Structure*.

- Wilson describes the delivery year RPM obligation as "unwanted" by a new capacity owner if there is a risk that it would back out of building the project at a later date. Put in terms of modern financial theory, by accepting an RPM obligation, the developer is giving up its 'real option' to delay building a resource. Although this is a potentially interesting point, in fact (as Wilson notes elsewhere), the three-year lead time of the RPM is not particularly generous relative to the time required to move from advanced development to commercial operation. The 'real option' value may be quite small, therefore, since the developer would likely begin full-scale development shortly after it cleared the BRA.

- Investors will, of course, consider more than a single year's worth of capacity prices in deciding whether to build or not. Like the stock market, however, the current capacity price imbeds a great deal of information about future capacity prices, so observing a robust capacity price today provides some assurance of robust capacity prices in the future, unless there are other observable indicators to the contrary.

Taken together, these considerations confirm the underlying economic conclusion that most new resources, except those under contract or owned by LSEs, will rationally choose to bid based on the fundamental economics of their units, and that this bid will approximate the Net CONE of a peaking unit (provided, of course, that that estimate is based on reasonable and current assumptions).

Wilson also takes issue with the timing of the BRA, noting that "RPM provides an incentive that, to the extent effective, is most valuable to capacity that can be built within a three year time frame, such as gas-fired resources."[37] It is unclear from Wilson's critique what, if anything, he would change. As Wilson recognizes, though, there is a balance that must be struck. On the one hand, some resources (such as nuclear and coal units) take much longer than three years to develop; on the other hand, some resources (such as some demand response resources) take much less. There can be, therefore, no single best lead-time for the BRA; during the RPM settlement conferences, the agreement was reached that three years represents the appropriate balance of interests for PJM.

3.1.4. Facilitating State Energy Priorities

Wilson makes several arguments that "the incentives created by RPM are not very consistent with [state energy] priorities." On close examination, none are critiques of RPM itself, but rather of judgments made by PJM in administering the tariff.

1. Energy efficiency and demand response. Wilson notes that some PJM states have set out ambitious—indeed, unprecedented—goals for demand reduction, while PJM itself has forecast continued load growth. Questioning whether PJM's forecast has

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37 Wilson at 78.

aligned its forecast with the states' goals, however, is not a valid critique of the RPM mechanism, but of the load forecasts that would feed into any resource plan.[38]

Wilson's argument on this point, however, loses sight of the fundamental responsibility of PJM and PJM utilities to take prudent steps to ensure system resource adequacy. At one point Wilson argues that PJM is over-procuring capacity because it does not reduce the load forecast within the state quickly enough. Later, though, Wilson argues that RPM "punishes" a state's customers if those demand response plans are delayed and, consequently, there is insufficient capacity. This "punishment" takes the form of higher prices, hopefully to attract new resources to make take up the slack left by delayed state action. In an energy-only market, the shortfall of resources would result in more frequent periods of very high prices, so RPM is emulating the unfettered competitive market that Wilson holds up as a standard.

2. Transmission. It is intriguing to see that Wilson avers that the RPM design—and, by extension, the Regional Transmission Expansion Planning Process (RTEPP) that informs RPM—is biased *against* transmission, while the staff of the West Virginia commission reached the opposite conclusion, namely that RTEPP favors transmission over new generation development in load pockets. Moreover, Wilson bases much of his argument on the contention that transmission owners in the east have a conflict of interest in building new transmission, which would reduce the value of generation owned (by an affiliate), while ignoring that fact that some eastern transmission owners, such as GPU, own little or no generation in eastern PJM and others, such as PEPCO, are net buyers of capacity. Moreover, the transmission planning process in PJM is driven by PJM itself.

3. Nuclear and coal. Wilson's concern is that such units cannot be assured of an advance payment under RPM but must "take into account long-term expectations of RPM prices." Again, the question has to be asked, what alternative works better for such units? In an energy-only market, all units are built in expectation of future energy prices, which are far less predictable than RPM prices. Under any system, baseload units may find it preferable to enter into long-term contracts to hedge their risks, but under RPM, those risks are reduced, making the contracting terms easier to agree.

Contrary to Wilson's assertions, a centralized capacity market such as RPM facilitates states' energy policy:

First, it provides transparent price signals for the capacity value imbedded in (most) energy resources. As LSEs seek to meet their responsibilities to meet environmental policies, they

38 ISO New England's FCM design allows the RTO to "buy back" capacity in reconfiguration auctions if capacity needs decline relative to the forecast at the time of the initial auction. Adopting a similar rule for RPM could address Wilson's concern, at least in part.

will face many choices between competing technologies and specific projects, each of which offers a unique combination of attributes, such as their emissions profile, their renewable status, and production cost of energy. Another important attribute is the resource's contribution towards resource adequacy. Choosing among competing projects, the LSE must assess the value of each of these attributes, and the transparent price signals from the CCM as to the value of the capacity component assists in developing cost-effective solutions to meet the full range of responsibilities an LSE faces in serving its customers, including meeting its share of the planning reserve margin.

Second, RPM fully accommodates self-supply of qualified capacity resources by LSEs. To the extent that states require their utilities and other LSEs to engage in direct procurement of preferred resources, these resources can be used to offset the resource adequacy requirement of RPM.

Third, PJM has suggested that the RPM design could be expanded to accommodate additional generation attributes directly. The original RPM design filed by PJM included operational attributes, as well as locational attributes. These operational attributes were oriented towards reliability characteristics, but in principle similar mechanisms could be used to acquire a quota of renewable resources, for example, or other preferred attributes.

Finally, RPM facilitates an orderly retirement of resources. As changes to environmental regulations make older, high-emissions plants less economic, the head-to-head competition of new and existing resources in RPM allows economically efficient replacement of resources.

3.2. Effect on Bilateral Markets

It is an unsurprising conclusion that bilateral markets for capacity in PJM are influenced by RPM auction prices, just as forward oil prices are influenced by spot oil prices. Wilson's lament about the purportedly adverse influence of RPM on bilateral contracting reduces, therefore, to little more than a lament that the RPM design now prices capacity at its true value. Under the prior capacity construct, capacity was under-valued, especially in constrained areas like New Jersey and Maryland (where Wilson's clients serve load). Consequently, bilateral contracts could exploit this low valuation and extract value from capacity suppliers. FERC determined, however, that this prior capacity construct produced prices that were too low, under the "just and reasonable" standard, and instituted RPM as a replacement. Now that the RPM 'spot' market for capacity no longer undervalues capacity, it is unsurprising that bilateral contracts at unduly low prices are no longer available, either.

Wilson claims that RPM undermines bilateral contracting between generation owners and LSEs because RPM prices "greatly exceed the net cost of new entry in some zones."[39] Wilson's report, however, provides no proof of this claim, and it ignores the economic forces

39 Wilson at 82.

that will drive RPM prices to equal the market-based cost of new entry. The only data that Wilson uses to support his contention that RPM may produce prices above the true Net CONE are contained in Figure 6A. The chart plots the RPM clearing price for RPM stacked with PJM's estimate of the E&AS offset for the 2007/08 delivery year. This sum is compared to the estimated Net CONE value for SWMAAC of $203/MW-day, and purports to show that the clearing prices in the RPM plus expected E&AS earnings markedly exceed the Net CONE. Wilson's Table 1 shows, however, that the Net CONE computed using an updated value of Gross CONE is $248.34/MW-day, substantially above the clearing price in any BRA to date. Furthermore, as shown in Figure 1 above, PJM's reserve margin for 2010/11 has fallen to close to the target level. Because new resources are needed to meet new load growth, it is entirely reasonable that the value of capacity should come close to the Net CONE value actually needed by new units. PJM's filed CONE estimates, which neither Wilson nor any load entity has substantively challenged, are still well above any RPM clearing price.

Wilson also asserts that the "uncertainty" created by RPM adds to the cost of bilateral contracting. As always, the question should be asked, "compared to what?" Compared to any other competitive market mechanism, a centralized capacity market mechanism such as RPM creates greater certainty as to the fundamental capacity value of a resource and therefore reduces contracting risk. Moreover, a robust capacity mechanism creates a liquid secondary market for capacity, further reducing the risk of entering into long-term contracts. Practical experience suggests that Wilson's concern is misplaced. Connecticut issued a Request for Offers last year that attracted competitive supply offers from dozens of parties that, collectively, offered several multiples of the capacity sought. Notwithstanding the fact that ISO New England operates a forward capacity market fairly similar to RPM, prices in this competitive solicitation were strongly competitive and, apparently, closely tied to unit economics rather than speculation.

3.3. Cost Effectiveness

Like other capacity markets, RPM pays all capacity in a given area the same price. To the extent that new capacity bids clear in the market, existing capacity receives the same payment. Although this is potentially far in excess of the going-forward costs of the units, this price is the true economic value of these incumbent units and, short of comprehensive discrimination enforced by FERC, will be reflected in the capacity prices in *any* resource adequacy design. There is neither theory nor evidence to support the belief that using a bilateral approach will sustain price discrimination between existing and new resources, which is responsible for most of the alleged cost increases that Wilson attributes to RPM. To the contrary, the efficiency and transparency of the RPM design should lead to clearing prices that would likely be *lower* than under a bilateral design. Even if a bilateral design could achieve some price discrimination, it would be imprudent regulatory design to attempt such discrimination and create the resulting distortions in investment decisions—which also would end up costing consumers more for the same level of reliability.

Any viable resource adequacy mechanism moves towards a common, locational clearing price for capacity. Moving to that goal quickly creates cost benefits for consumers through greater regulatory certainty for investors, lower transaction costs, and lower compliance costs as well as greater reliability through a multi-year forward showing. At the same time, RPM fully supports bilateral contracting, so any cost benefit from long-term contracts attributed to other plans can also be realized in RPM. Any design, however, that fragments the market or clouds price transparency risks increasing consumer costs, not lower them. Consequently, the RPM market design provides a central market with transparent prices.

There are at least three elements that appear to be agreed among substantially all parties, about the desired structure for a resource adequacy mechanism: a standardized capacity product, a mandatory reliability planning margin, and transparent markets. Once there is a standardized product, and a mandated demand for that product, a market for the product naturally results. That market can either by well designed and capable of revealing the underlying value of capacity, or it can be poorly designed, resulting in low liquidity and reduced pricing transparency. This latter case results in inefficient investment decisions and excessive costs. A well-designed market, such as RPM, improves investment decisions that ultimately lower consumer costs.

Moreover, it is bad public policy to attempt to institutionalize price discrimination among resources. It can result, perversely, in higher costs to consumers. If new resources perceive a risk that they will receive lower capacity payments once they are "existing," they will either demand a premium up front to offset expected future price discrimination, or they will demand long-term contracts. These contracts mitigate the regulatory risk of the unit but also transfer other risks to consumers, such as the risk of obsolescence and technology choice, that would be borne by the generation owner in an efficient market design. Furthermore, seeking to systematically underpay existing resources creates perverse incentives, either to make investments that would reclassify a unit as "new," even if those investments would not be economic on their own merit, or to retire a unit that has better going-forward economics than the all-in cost of a new unit but would earn lower profits, because of the systematic discrimination between new and existing resources. Stated another way, any attempt to discriminate between new and old resources leads to premature retirement of "old" resources and a corresponding overreliance on more expensive "new" resources. Regulators have tried several discriminatory "vintaging" schemes before, most notably with natural gas in the 1970s; each has come unglued for precisely the reasons discussed here.[40]

Once we can let go of the idea that systematic discrimination between new and existing resources can be achieved, the goal of a resource adequacy market should be to reduce the offer prices of new capacity resources, which will, on average over time, set the clearing prices in the market. The most effective way of reducing entry costs is to eliminate

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40 The legal history of the natural gas vintaging issues is well summarized in the Supreme Court opinion in *Mobil Oil Exploration v. United* Distribution, 498 U.S. 211 (1991). A broader history of natural gas deregulation is Robert J. Michael "The New Age of Natural Gas," Regulation 16 no. 1 (Fall 1993).

unnecessary risks, while at the same time leaving those risks under the control of developers with developers. RPM strikes this balance reasonably well, and certainly better than a purely bilateral design.