American Public Power Association

“Missing Money” Revisited: Evolution of PJM’s RPM Capacity Construct

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I. Introduction

This paper discusses the evolution of PJM Interconnection, LLC's Reliability Pricing Model ("RPM") resource adequacy mechanism and recommends goals and directions for its further evolution. The RPM capacity construct was originally designed to be a residual, "as-needed" market intervention to address specific, transitional market design shortcomings and ensure enough generating capacity to meet peak demands. However, over time RPM has come to play a larger role in the PJM region marketplace. Chronic excess capacity, due to overly optimistic load growth forecasts and new gas-fired generation (among other forces) has depressed energy prices and led generators to seek more revenue from RPM. Several iterations of changes, including the recent major package of "Capacity Performance" ("CP") tariff revisions, have generally resulted in more stringent eligibility requirements and performance obligations for capacity providers, among other changes that should support higher capacity prices. However, the attempts to raise capacity prices continue to be thwarted by new entry, primarily demand response and gas-fired generation.

RPM's evolution has not been driven by the parties directly affected by resource adequacy, who also ultimately bear the associated cost. Most of the changes were opposed by electricity consumers and their representatives (state consumer advocates, regulatory commissions, and public power entities). Instead, most revisions to RPM have been promoted by the grid operator, PJM (who is responsible for reliability and resource adequacy, but not its cost), and generation owners who benefit from higher capacity prices.

The PJM region's resource mix is undergoing a major shift with renewable and natural gas-fired capacity replacing retiring coal plants. The demand side is also changing, as electric loads become increasingly dispatchable and price-responsive. The changing resource mix presents new challenges and opportunities for electric system operation and creates a need for new types of flexible resources. RPM, focused around a standard "capacity product" to meet peak day demands, is ill-suited to guide the capacity additions that will be needed as the resource mix changes. The current RPM construct also works against the transition in the resource mix, by concentrating revenue recovery in the administrative, years-forward standard capacity product, rather than in the more granular energy and ancillary services markets and voluntary long-term contracts. While some states and load-serving entities would like to take a more active role in guiding the changes in the resource mix – for instance, encouraging environmentally-preferred types of resources, and flexible resources needed to support the increasing penetration of intermittent resources – some of the recent changes to RPM have been directed toward preventing such "out of market" actions.

This paper suggests a longer-term path for further evolving RPM toward a voluntary mechanism, allowing revenue recovery to shift back to the "real" markets (for day-ahead and real-time energy and ancillary services, and longer-term, voluntary physical and financial hedges), to fully realize the potential benefits of competitive wholesale electricity markets as the resource mix changes.

II. The Rationale for Capacity Constructs Such as RPM

In principle, bid-based energy and ancillary services markets can balance supply and demand on the electricity grid in the short-term while also providing adequate incentives to retain existing capacity and develop new resources where and when needed. In markets for other goods and services, forward markets that provide advance price and quantity commitments (such as RPM is intended to provide) develop naturally, to the extent buyers and sellers desire forward certainty about supply arrangements and prices (as they do, for electricity). For wholesale electricity markets, too, administrative capacity constructs such as RPM were not part of the original concept, nor are they now considered necessary.[1]

However, when the electric utility industry was being restructured and wholesale electricity markets established years ago, there were concerns that traditional, conservative resource adequacy targets (such as the widely-used "one day in ten years" criterion[2]) would not be met through voluntary arrangements under the new market arrangements. Due to the lack of engagement of the demand side in the markets at the time, demand was highly inelastic, so price mechanisms could not be used to balance supply and demand at times of peak demand.[3] This led to price caps and concerns about "missing money": inadequate incentives for market participants to provide enough capacity to meet peak period demands.[4] RPM, and similar mechanisms in New England and New York, were put in place to address these alleged market shortcomings by acquiring forward commitments to provide enough capacity to satisfy administratively-set targets.[5] Such constructs are supposed to provide the missing money, which in theory should be the same for all types of resources when the resource mix is in equilibrium.[6] These constructs are mandatory, and the cost is imposed on all consumers, based on the concept that resource adequacy is a "public good" that can only be provided in common for all consumers.

Note that resource adequacy is a very different issue from transmission system reliability. Because transmission system disruptions can result in widespread, costly blackouts, PJM (and other Regional Transmission Organizations, "RTOs") understandably consider the reliability of the transmission grid an interest that trumps, rather than being balanced with, cost considerations. By contrast, should a resource shortfall ever result in load drop, it would likely be small and controlled. When demand pushes up against available supply on a peak day, prices rise according to the RTO's administrative shortage pricing rules to clear supply and demand; and in the unlikely event a rotating outage is required to preserve sufficient reserves to operate the transmission system reliably, most likely only a small quantity would be curtailed, with advance notice, in a controlled manner, and avoiding circuits with the highest-priority customers. So while reliability concerns may trump economics when it comes to the transmission system, resource adequacy policies should attempt to balance the cost of a program against its value in avoiding lost load.

In recent years, the market design shortcomings considered to cause missing money and create the need for a capacity construct have largely been addressed. The demand side is more engaged, through demand response programs and price-responsive demand, and shortage pricing rules ensure that prices reach high levels as necessary when demand pushes up against available supply. As a result, the energy and ancillary services markets are increasingly able to clear and set prices even when capacity is scarce, improving the ability of energy markets to set strong prices signals for new capacity when it is needed. Note also that when prices during scarcity can reach levels close to the "Value of Lost Load" ("VOLL"), the value distinction between voluntary and involuntary load drop is eliminated, and resource adequacy criteria such as "one day in ten years", which are based on that distinction, lose meaning.[7]

Note also that the "public good" aspect of resource adequacy – the notion that resource adequacy can only be provided in common for all grid users, because outages cannot be imposed only on those consumers whose supplies are short – is also changing with the further development of the demand side, and new grid technologies.

Most grid users continue to be exposed to occasional disruptions resulting from distribution or transmission system disturbances (while others have invested in back-up systems or otherwise self-provide reliability). Some grid users would like the grid to be highly reliable, and would be willing to pay more for that, while other users, for instance those with backup power supplies, may place little or no value on such reliability. However, for customers that remain dependent upon power delivered through shared wires, distribution and transmission system reliability will continue to be treated as public goods paid for and provided in common.

In contrast, the amount of generation a customer or group of customers has arranged can increasingly be a private choice. Involuntary load drop has been extremely rare, and it should become even more unlikely in the future with increasing demand response, advanced metering, and controllable, price-responsive end-use devices. As the wholesale and retail electricity markets are further developed, new technologies will allow reducing the extent to which resource adequacy must be treated as a mandatory public good.

III. RPM: Original Design and Subsequent Evolution

RPM had the following principal features when it was first implemented in 2007:

- Capacity quantity targets were based on peak load forecasts and target reserve margins for the RTO and a small number of zones.
- Auctions were held three years forward to acquire one-year commitments from existing and planned resources to meet the identified RTO-wide and zonal capacity targets.
- The auctions used sloped capacity "demand" curves for each zone, to set higher zonal prices when offered supply is relatively scarce, lower prices when capacity is abundant ("price signal").
- "Residual" capacity procurement: RPM auctions were intended to acquire capacity only to the extent capacity requirements were not met by market participants' self-supplied resources and bilateral contracts; there was also a (highly limited) opportunity to "opt out" of RPM.
- Supplier market power was mitigated by must-offer requirement and offer price caps based on going forward cost net of estimated net revenues from energy and ancillary services markets.
- Capacity providers were subject to penalties for non-performance.

The RPM design, which resulted from a settlement, was intended to accommodate both restructured and non-restructured states, and also the range of business models found within the PJM footprint: in particular, merchant power plants, vertically integrated utilities, and public power and consumer-owned entities. In the first years of operation, the RPM design was augmented to accommodate demand response as a capacity resource, and to provide additional flexibility to adjust capacity commitments in "incremental auctions" closer to the delivery year.

Over time the RPM capacity construct has evolved not as electricity market theorists had hoped -- withering away and no longer needed as the energy and ancillary services markets developed – but instead as consumer interests had feared – toward a large and costly role in the wholesale markets. Most of the recent changes were promoted by PJM, and/or by generation owners with PJM's support, and are consistent with PJM's and generation owners' interests rather than consumers' interests. Nor have the changes been guided by a vision of how the wholesale markets should ultimately be organized and the ultimate role, if any, of a capacity construct in those markets.

As noted earlier, RPM prices are intended to provide additional revenue to attract and maintain sufficient capacity; in concept, revenues from energy and ancillary services revenues, plus capacity payments, should equal the amount necessary to attract new entry (the "Cost of New Entry", or "CONE"). In theory the sloped RPM demand curve should result in a self-correcting dynamic: when capacity is short, RPM prices will be high and encourage entry; when capacity is long RPM prices will be low and discourage entry while encouraging retirements. However, in practice, energy and ancillary services revenues plus RPM revenues have generally remained far below administrative CONE estimates, and also below many asset owners' actual requirements and/or desires. The retirement of many coal plants during 2012 to 2016 was absorbed without capacity prices approaching the administrative "Net CONE" level (based on an estimate of CONE minus an estimate of future energy and ancillary services earnings) that supposedly is necessary to attract new entry. Over the past several years RPM has consistently cleared a reserve margin approximately four percent above the conservative targets.[8] While these outcomes were partly due to weak load growth, a primary cause was robust new entry by gas-fired resources, suggesting that the administrative Net CONE estimates may be far too high.

Total generator revenues below administrative Net CONE led capacity sellers and PJM to seek to increase revenues to generators. However, energy and ancillary prices result from well-established markets that will tend to set low, cost-based prices when there is excess capacity, while even small changes in RPM rules or parameters can have a large impact on capacity revenues. Consequently, the primary attention has been on raising RPM prices and revenues by addressing various alleged shortcomings in its design and adjusting various parameters. These attempts have operated on both the supply side (e.g., by restricting resources) and the demand side (increasing capacity purchase quantities).

PJM's various proposals for RPM design changes have focused on resource adequacy and capacity price outcomes. As an RTO, PJM is responsible for the design and administration of wholesale markets and for transmission and reliability planning, and can anticipate criticism and repercussions from any problems stemming from these areas of responsibility. However, PJM is not held responsible for the costs resulting from its planning, market design or reliability-related activities. The various changes to RPM over time have generally reflected PJM's interest in more capacity, committed sooner and more firmly, with more stringent performance requirements, and at higher prices to keep capacity providers profitable;[9] the changes have not always balanced these outcomes with their associated costs or long-term market impacts. Through 2014, the following changes to RPM were implemented (among many others):

- "Minimum Offer Price Rule" ("MOPR") to prevent entry by subsidized or contracted generation.[10]
- Stricter rules on demand response participation; hard limits on seasonal resources. [11]
- Stricter rules on capacity imports; hard limits on imports.[12]
- Redesign of the RPM capacity demand curve, increasing capacity purchases and prices. [13]
- Changes to the Net CONE calculation, sharply increasing Net CONE. [14]

However, despite these changes, RPM prices remained well below the administratively-determined Net CONE levels.

Then January 2014 brought the "polar vortex" period of extreme cold. The PJM region is summer-peaking, and over the two decades before this event, generally had substantial excess capacity in the winter months, with low energy prices. Accordingly, generation owners had not seen value in investments for winterization or firm winter fuel supply - not all capacity was needed in winter, and winter energy prices were unlikely to justify investments to prepare for very rare conditions. The extreme cold early in January 2014 caused a very large amount of generating capacity (more than a fifth of the PJM region installed capacity) to become unavailable, due to a variety of weather- and fuel-related causes.[15] While there was no loss of load, reserves were very short and energy and ancillary services prices were very high, reflecting the low reserves and high natural gas prices at the time. Extreme cold later in the month also resulted in relatively high levels of plant outages, and high prices.

The polar vortex event served as a wake-up call for generation owners, who learned that their capacity can be more needed and valuable in winter than it had been during winter periods for decades. The generation that performed poorly in January 2014 missed out on substantial earnings in energy and ancillary services markets. As a result of actions taken by generation owners, and also various initiatives by PJM to bolster winter preparedness, generation performance was greatly improved in the winters of 2015 and 2016. [16]

However, following the polar vortex event, PJM also conceived and implemented a major package of changes to the RPM design, termed "Capacity Performance" ("CP"). The CP provisions, which were similar to "Pay for Performance" provisions added to ISO New England's capacity construct at about the same time, were designed primarily to create stronger incentives for capacity providers to be available under system stress conditions when capacity is most needed. CP was a reaction to the polar vortex – few of the CP provisions were even under discussion before that event – but the provisions were consistent with earlier efforts to tighten up RPM and raise its prices. The CP provisions included the following: [17]

- A new "Capacity Performance" capacity product with more stringent eligibility requirements and performance obligations, including multi-day performance over the annual period. A "Base Product" that accommodates demand response and seasonal resources is retained for only a transitional period (through the May 2016 auction for the 2019/20 delivery year).
- Greater penalties for failure to perform during periods when capacity is needed (with a "no excuses" approach, for instance, for lack of fuel).
- Further shift of the capacity demand curve through elimination of the 2.5% holdback for short-term resources.
- Relaxation of supplier market power mitigation, in light of the difficulty of quantifying the risks associated with providing the CP product with its higher penalties.

As a result of more stringent eligibility requirements and performance obligations in an annual product, CP is expected to reduce the participation of some types of resources in RPM, including demand response, renewables, and poor-performing older plants, once the transition is completed. CP is expected to lead to higher offer prices in RPM's auctions, due to the increased cost and risk of providing capacity and relaxed supplier market power mitigation. Through RPM's auctions, less offered capacity and higher offer prices result in higher capacity clearing prices and higher capacity costs. For the first three affected delivery years (2016/17 through 2018/19), the additional cost of CP has been estimated at $7 billion.[18] The total cost of RPM capacity commitments, which ranged from four to eight billion dollars per year over the first eight RPM delivery years, will reach eleven billion dollars for 2018/2019.[19] However, in the most recent RPM auction (in May 2016, for the 2019/20 delivery year), in which a limited amount of non-CP resources was still accepted as a transitional measure, clearing prices fell far short of expectations and of administrative Net CONE values,[20] as new entry continues to moderate RPM prices.

To a great extent the current RPM design reflects PJM's desire for forward certainty about the resources that will be available to meet peak loads in future years, and PJM's lack of confidence in voluntary forward markets. Rather than support development of markets for physical bilateral contracts and financial hedges, as exist for other commodities, PJM took the approach of imposing ever more stringent and costly forward performance requirements through the administrative RPM capacity construct which, according to the current auction parameters, must now provide 77% of the revenue required to attract new entry. [21]

All of PJM's proposed changes to RPM were subject to approval by the Federal Energy Regulatory Commission ("FERC"). However, FERC considers the RTOs to be independent and objective, and generally affords wide deference to their proposed tariff changes. FERC, like the RTOs, is primarily concerned about maintaining reliability and resource adequacy, and, like RTOs, may not always require a balance between the value and cost of the associated policies.[22] Thus, RPM's evolution has reflected the ironic situation where PJM proposes, generation interests support, and FERC approves changes to RPM that purportedly are needed to bolster resource adequacy, while representatives of the consumers directly affected by resource adequacy (and who ultimately bear its cost) have frequently opposed the changes as unnecessary and overly costly.

The changes to RPM over the years have been vetted through stakeholder processes in which interests have often been polarized along these lines. Often the upward impact on capacity prices and costs is rather clear and short-term, while the direct or indirect impact on resource adequacy and market efficiency may be longer-term and theoretical. As a result, RPM rule changes submitted to FERC for approval have usually lacked broad-based stakeholder support.

IV. The Current RPM Design: Critique

This section summarizes the primary inefficiencies inherent in the RPM design as it now stands after a decade of revisions, and why RPM is ill-suited to guide changes in the resource mix going forward. The fundamental problems are two: 1) the necessity of defining a standard capacity product, in order to use auctions to acquire commitments; and 2) holding the auctions three years forward, while keeping the commitments short (which is necessary due to the standard product). The inefficiency that results from these two characteristics is exacerbated by a third key aspect of RPM: the chronic excess capacity that has resulted from various other RPM design features and parameters.

1. Standard Capacity Product

The use of auctions to select capacity providers based on their price offers requires the definition of the capacity "product", which necessarily must specify all of the performance obligations and consequences that would apply to the offered capacity. Potential sellers must know exactly what they are selling to be able to offer a price for it in the auction. The details of the capacity product are determined administratively and identify the specific performance obligations and various penalties for not meeting the obligations. Many of the details are quite arbitrary, but very important, because they differentially impact different types of resources. In particular, the product design will differentially impact resources with different forced outage rates, fuel supply arrangements, ramping and minimum load levels, and environmental restrictions, among other operating characteristics. But ultimately, the capacity auction sets a single price that applies to all capacity providers, which, together with the performance and penalty provisions, implicitly values these characteristics. The RPM capacity product definition has been changed over time, and underwent a major re-design with the recent CP rules.

In the changing electric power industry, consumer needs will be met with an expanding variety of resources, including traditional, central station coal, nuclear, natural gas and hydroelectric power plants, wind, solar and other renewable sources, and also distributed forms of generation and energy storage, among other existing and emerging technologies. There is increasing participation of the demand side, including both resources dispatched by the system operator (demand response), and also customers and devices that adjust consumption based on actual prices (price-responsive demand). The various types of resources have different operating characteristics and their contributions to resource adequacy and system operation are of course different and vary over time. State and federal policies will continue to influence the changing resource mix, for instance, by encouraging development of renewable and low-carbon sources of generation and more efficient use of energy. Because the variety of possible objectives and preferences of various policymakers and wholesale buyers cannot be accommodated within a standard capacity product, these preferences will continue to be reflected in "out of market" actions.

Resource adequacy and reliable system operation result from aggregate resource performance at any time, not the performance of any individual resource. Resource adequacy targets will be satisfied most efficiently and at lowest cost if the contributions of all types of resources are recognized and properly valued. Wholesale energy and ancillary services markets, and distributed energy resource platforms operating underneath them,[23] naturally value resources rather accurately on an hour-by-hour basis, by rewarding in each hour those resources providing the needed services during the hour. By contrast, administrative capacity constructs will recognize the variety of contributions to resource adequacy very imperfectly, due to the standardized capacity product required for the single-price auctions, and the standardized performance requirements and associated penalties. Table 1 summarizes the differences between energy and ancillary services markets and capacity constructs such as RPM in this regard.

In addition, under the CP rules, RPM imposes substantial penalties on resources that fail to perform during Performance Assessment Hours (those hours when the system is under some stress and an emergency or pre-emergency action has been announced). The penalties are based on an administrative formula that is not connected to the actual market value of the performance at the time, and the penalties may greatly exceed the market value at times (at other times the penalties may fall short of market value). By creating and imposing additional risk and uncertainty, RPM discourages the participation of some resources (in particular, demand response, seasonal, and intermittent resources) and raises the cost and risk of participation by other resources, creating inefficiency and applying upward pressure on RPM prices and cost.

2. Three-Year-Forward Procurement/ One-Year Commitment

RPM's three-year-forward procurement of one-year commitments reflects the muddle, present in the RPM design from the very start, as to whether it is supposed to be just a residual capacity spot market, or instead should be trying to set a long-term price signal. This muddle dates back to a 2003 report by NERA Economic Consulting for PJM, NYISO and ISO New England ("CRAM Report"[24]), which discussed the advantages and disadvantages of short-term or longer-term capacity commitments. The CRAM Report ultimately recommended three-year commitments (neither short nor long),[25] a recommendation that was not followed in the RPM design (nor was it adopted for the NYISO or ISO-NE capacity constructs).

A capacity spot market would involve auctions held close to each delivery year for short-term commitments, to top off resource commitments to meet any residual near-term need for capacity to satisfy resource adequacy targets. The clearing prices would reflect the short-term supply-demand balance and, therefore, could be relatively volatile. The MISO and NYISO capacity constructs hold auctions close to the delivery year. Under such "prompt" constructs, prices are understood to reflect short-term market conditions, and price outcomes are not expected to signal the longer-term need for new capacity.

RPM was designed with auctions held three years forward to accommodate participation by proposed new power plants that have not yet committed to construction. This led to hopes that the offer prices from such plants, and resulting RPM clearing prices, would reveal the long-

Table 1: Comparison of Energy and Ancillary Services Markets and the RPM Capacity Construct With Respect to the Valuation of Services and Resource Attributes

	Energy and Ancillary Services Markets	RPM Capacity Construct
Service	Actual energy and ancillary services needed for reliable system operation	Administrative capacity "product": commitment to readiness and performance in future year
Structure of services	Highly granular: energy and ancillary services; highly locational; hourly/ sub-hourly; real-time and day-ahead	Single annual product ("Capacity Performance"), for a few zones
Pricing	Highly granular by service, location, time	Single annual price for each zone; prices also set in incremental auctions for each delivery year
Competition	Bids generally cost-based and competitive; excess capacity in nearly all time intervals	Market power is endemic because the capacity construct seeks commitments from nearly all available capacity and ownership is highly concentrated
Risks	Risks associated with participation small; offers made and prices set near time of performance, and highly granular	Risks substantial due to multi-year forward commitments for annual periods, potential for substantial non-performance penalties
Price v. value	Prices reflect value of service based on competitive, cost-based bids (except in rare periods of scarcity) and highly granular supply/ demand conditions (service, location, time)	Prices result from auctions that reflect numerous administrative determinations (future load forecast, "1 in 10", target reserve margin, Net CONE, etc.) and offers that reflect market power mitigation and seller offer strategies; may not reflect value
Cumulative revenue v. value	Cumulative net revenues for each service signal the value of and need for the specific service and the attributes necessary to provide it (such as flexibility, ramping, etc.)	Capacity prices reflect capacity supply/ demand and various administrative determinations reflected in auction outcomes; actual relationship to "missing money" is unclear
Forward markets, price signals for new resources	Forward markets provide physical and financial hedges of potential costs and risks of the short-term markets; forward prices reflect anticipated value of specific resources based on the specific services each type of resource would provide	Forward markets must also anticipate revenues from an administrative capacity construct over time – more influenced by administrative and regulatory determinations, more uncertain, less connected to actual value, and heavily discounted by investors

term average capacity prices needed to attract sufficient new entry (true "Net CONE") – a long-term price signal. However, the expectation that new entrants would through their offers demand Net CONE for one-year commitments was misguided. New entrants' considerations in selecting their offer prices are complex, but they generally do not have incentives to offer at prices close to Net CONE (not administrative Net CONE, nor their private estimates of Net CONE) for these one-year commitments,[26] and are more likely to offer as price-takers (at very low prices), as RPM results have now repeatedly revealed.[27] The muddle as to RPM's role, with some stakeholders viewing RPM's role as a capacity spot market for residual procurement, and others viewing RPM as intended to create a longer-term price signal and hoping that it would do so, has afflicted discussions of design changes since RPM was first proposed.[28] Perhaps the most problematic consequence of the hope that RPM would create a long-term price signal has been the repeated efforts to modify its rules to achieve that result and to protect RPM price formation from various outside pressures (such as the MOPR rules, discussed further below).

Another drawback of a three-year-forward commitment is that it can impose substantial risks on both planned resources (whose on-line dates may be delayed for various reasons) and existing resources (that, for instance, may suffer a major component failure rendering performance infeasible or uneconomic). While some flexibility to adjust commitments after the three-year-forward auction is provided, PJM and capacity sellers have attempted to limit such flexibility through more recent proposals for RPM design changes. [29]

Three-year-forward auctions are also inefficient because will they tend to over-price capacity relative to the true anticipated supply-demand balance, due to overstated demand (also discussed below) and understated supply.[30] Supply is understated three years forward because some short lead-time resources that will be available in the delivery year will not be eligible to participate in three-year-forward auctions, while some existing resources that will be available may fail to clear because the owner wishes to maintain the flexibility to retire the capacity.

Note that moving to longer term commitments through RPM, as originally suggested by the CRAM Report, if feasible at all, would not be an improvement. With longer-term commitments, the administrative capacity construct would play a much larger role in determining which new resources will and will not be built; so the fact that it is not feasible to take into account the great variety of resource attributes within the standard capacity product definition needed for single price auctions would become an even more serious defect. And even if some attempt were made to consider various resource attributes through the auctions, different states, load-serving entities and consumers will value the attributes differently, so there would be no consensus on how offers should be evaluated and the winners and losers chosen within the auctions. This is the fundamental problem with longer-term commitments through RPM, but there would be many other issues to be addressed, such as what fraction of the requirement to acquire under longer-term arrangements and of what duration, and how to allocate the cost onto consumers, which would become especially problematic when the long-term arrangements are well above market.

3. Provisions and Parameters Leading to Excess Capacity

Various RPM features also contribute to clearing capacity quantities that are in excess of true needs for resource adequacy. RPM has consistently cleared excess capacity in recent years, and the most recent auction (for the 2019/20 delivery year) cleared the largest excess ever.[31] The main contributors to excess capacity are the following:

- The conservative "one day in ten years" resource adequacy criterion;
- Various conservative assumptions underlying the calculation of the reserve margin needed to meet this criterion (of which perhaps the most significant is the understatement of the potential for assistance from diverse neighboring regions when needed);[32]
- Chronically overstated load forecasts (the target procurement quantities in RPM auctions are essentially the load forecast times the reserve margin);[33]
- Administrative Net CONE values that overstate the prices needed to attract sufficient new entry, raising the capacity demand curve and resulting clearing prices;
- The conservative capacity demand curve shape that generally clears quantities well above the target at a broad range of price levels. [34]

RPM clearing prices considered low by capacity providers have led to pressure for changes to the rules to attempt to raise prices, of which some (such as raising Net CONE values, and further shift of the demand curve) temporarily raise RPM prices while further exacerbating the excess capacity situation.

Clearing excess capacity results in excess supply and low prices in energy and ancillary services markets. This devalues resources that mainly earn revenues in those markets (such as intermittent resources and nuclear generation), and further shifts generation revenue recovery to the capacity construct. [35] The increasing penetration of renewable resources with very low variable costs is expected to place further downward pressure on energy prices in the coming years and increase the need for resource attributes (such as fast-ramping ability) that are not fully valued when there is excess capacity. [36]

V. Looking Forward: Additional Reasons to Move Beyond the Current Design

There is dissatisfaction with the RPM design and its outcomes on both sides of the market at present, as there has been throughout its lifetime. Capacity sellers (especially owners of existing generation who would like to rely on RPM as the sole source of revenue to augment energy and ancillary services markets revenues) view RPM prices as too low and unpredictable and its one-year commitments as too short. Many consumer interests have long doubted the value received from the billions paid through RPM, and wonder whether more economical and/or less administrative approaches could suffice. Capacity sellers allege "price suppression" from multiple causes leading them to seek barriers to entry and interventions in price formation to support higher clearing prices. Consumer interests note the multiple rounds of changes to RPM that seem directed largely at raising its clearing prices.

RPM, and the capacity constructs in New England and New York, all include a MOPR, which were originally put in place to prevent deliberate attempts by capacity buyers to suppress prices.[37] More recently, the focus has shifted to state actions to encourage and subsidize certain new or existing resources. State actions with the intent to lower prices can harm markets and, ultimately, consumers (harming market participants in the short-term by suppressing prices, and harming consumers over the longer term due to the negative impact on investor confidence). However, over the past several years the MOPR rules have been re-purposed with the broader objective of preventing any price impact of "out of market" resources.[38] These rules now generally apply without regard to the presence or absence of an ability, incentive, or intention to affect price, and also without regard to whether the actions being mitigated are in pursuit of legitimate public policy goals.

State and federal policies will continue to influence the changing resource mix, to address the environmental impacts of fuel use, encourage development of renewable and low-carbon sources of generation, encourage more efficient use of energy, and/or in pursuit of other public policy objectives, such as resource diversity or economic development. The variety of possible objectives and preferences of various policymakers and wholesale buyers cannot be accommodated within a construct that procures a standard product through an auction, as PJM has acknowledged.[39]

State actions to influence the evolving resource mix, and calls for regulatory actions to prevent or offset the potential impacts of such actions, seem to be growing more frequent. For example, the Public Utilities Commission of Ohio approved contracts to financially support existing in-state generation with the stated goal of providing consumers a physical hedge, which led to a complaint alleging this would distort market prices.[40] In New England, state programs to support construction of new natural gas pipeline capacity to serve growing gas-fired generation led to a complaint[41] alleging the actions are intended to suppress gas and power prices, and which proposed, by way of relief, various adjustments to price formation in ISO New England's energy and capacity markets.

Whether or not the impacts of such state actions warrant mitigation, it should also be noted that the extent to which such "out of market" resources do in fact affect wholesale prices can only be estimated, and such estimates require making various assumptions about how markets would respond. Under many circumstances, such as when the new resource is quite small relative to the size of the market, or when there is a substantial amount of market entry and exit at any time, there may be little or no impact. For resources that are anticipated well in advance (for instance, resources resulting from programs put in place after lengthy state regulatory processes), it can be expected that the markets will have adapted to their anticipated presence through adjustments to the timing of other new entry and retirements. Estimates of the impacts of out of market resources often assume markets do not respond and adapt to them, resulting in overstating the price impacts and potential harm.

While the U.S. Supreme Court's decision in *Hughes v. Talen Energy Marketing*[42] found certain state actions illegal for their linkage to wholesale market pricing, the narrow ruling left substantial scope for state actions to shape the resource mix by encouraging and subsidizing resources with favored attributes. It can be expected that policy makers will continue to take actions that influence the evolving resource mix, and market participants will continue to seek regulatory fixes for the potential price impacts of such actions. While some public policy objectives can potentially be addressed with "in-market" approaches to some extent (for example, carbon pricing), the potential of such approaches is limited, because they impose the same price on all customers, and consensus is likely to be lacking.

The vigorous attempts to "protect" capacity price formation from such forces reflect the outsized importance of these constructs at this time. A residual, prompt spot capacity market would be expected to result in volatile prices, and buyers and sellers alike would avoid relying on it except for small portions of their portfolios, instead focusing on bilateral contracts or financial hedges to determine the bulk of their costs and revenues. And it would be accepted that capacity spot market outcomes might at times reflect actions or events that raise or lower prices, and that might not be fully consistent with a purely competitive market, such as short-term market power, or last-minute actions by market participants or policy makers that affect supply or demand. With small volumes at stake and anticipating volatile prices, market participants would not be so quick to call for regulatory interventions in price formation unless it was fairly clear that illegal manipulation or exercise of market power was involved.

The idea of a forward capacity market was first conceived in detail in the 2003 CRAM Report, which emphasized that to work, a centralized forward capacity market would have to gain the trust and confidence of market participants and achieve regulatory and institutional certainty.[43] However, after ten years, a consensus of market participants in support of RPM has not formed; consumers have seen multiple rounds of changes that they have considered unnecessary and overly costly, while many generators believe RPM is flawed and sets prices that are too low. After ten years, stakeholders continue to struggle over RPM modifications, regulatory and institutional certainty has not been achieved, confidence in the construct has not been established,[44] investors continue to heavily discount future capacity revenues,[45] and pleas for stakeholders to believe in and trust centralized capacity markets continue.[46]

VI. Recommended Goals for the Further Evolution of the RPM Construct

This paper has described how PJM's RPM capacity construct, first implemented a decade ago to address a specific resource adequacy concern, has evolved into an expanded role over time. While the market design flaws that provided the original rationale for capacity constructs such as RPM – lack of demand side involvement and price caps – have largely been addressed, RPM, with its standard capacity product, three-year-forward/one-year commitment, and tendency toward excess capacity, is ill-suited to guide the resource additions that will be needed in the coming years and to accommodate federal and state efforts to influence the evolving resource mix. This paper proposes the following goals for the further evolution of the RPM capacity construct:

- To see a greater portion of generators' revenues gained from the energy and ancillary services markets and long-term voluntary contracts rather than the administrative capacity market; the role and importance of the capacity construct and its payments should decline;
- To see capacity quantities more in line with realistic forecasts of peak loads and reserve requirements, leading to less excess capacity, more meaningful prices in energy and ancillary services markets, and stronger incentives for demand side involvemen;
- To encourage and accommodate all forms of longer-term resource arrangements, including physical contracts and financial hedges;
- To accommodate the resource decisions resulting from public policy initiatives and the choices of market participants with different business models without interference;
- To increasingly allow "resource adequacy" to reflect market participants' preferences and choices (distinguishing it from transmission grid reliability, for which planning and operation will remain highly centralized under the RTO);
- To facilitate more active involvement of the demand side both in short-term markets (demand response, price-responsive demand) and in longer-term markets (bilateral contracts and financial hedges);
- To clarify the administrative capacity construct's role as a residual capacity spot market whose prices reflect the short-term supply-demand balance resulting from the various actions of market participants and policy makers; to let go of the aspiration for the capacity construct to produce a long-term price signal;
- To allow price formation in the capacity construct to occur without interventions to attempt to adjust or offset the alleged "price suppression" of certain market (or "out of market") actions (policies regarding exercise of market power or market manipulation apply);
- To work to reduce the "public good" treatment of resource adequacy – to the maximum extent, operational procedures should impose the consequences of any resource shortages according to market participants' arrangements, and consumers and load serving entities should be empowered to take full control and responsibility for this aspect of their electricity service, while continuing to offer reliable "default" services for customers (generally smaller customers) unable or unwilling to participate in such arrangements.

VII. Paths Toward More Efficient and Voluntary Wholesale Electricity Markets

Many of the above goals reflect a vision with a smaller role for RPM over time. This vision is of course contrary to the recent evolution of RPM, which has involved numerous changes directly toward raising RPM prices and increasing its role, among other objectives.

Progress in evolving RPM toward a more voluntary construct can be made incrementally, by expanding the opportunities to make alternative arrangements. Progress can come both top-down and bottom-up. The top-down approach would involve accommodating decentralization of resource adequacy responsibility from the RTO to distribution utilities (public, consumer-owned, or investor-owned), load-serving entities, and/or subsets of the grid that meet eligibility requirements. Eligible entities would be permitted to establish their own procedures for addressing circumstances when the demand on their systems could exceed the supplies arranged to serve the load. The eligibility requirements would entail metering and control technology, and agreement to the grid operator's procedures for reducing deliveries when aggregate demand exceeds arranged supplies. (RPM's current Fixed Resource Requirement, or FRR, provisions are of this nature, however, FRR eligibility is highly restricted, and the rules are overly proscriptive.) The bottom-up direction would involve expanding the opportunities for individual customers to forego the resource adequacy program of the grid operator, distribution utility or load-serving entity. The eligibility requirements would entail metering and control technology, and agreement to protocols that may entail penalties.

The mandatory aspect of RPM could be phased out according to the following plan:

1. RPM's three-year forward auctions would become

voluntary for a broad class of eligible entities, starting with a delivery year five years out (2022-2023). The timetable would allow states, distribution utilities, load-serving entities and eligible consumers to decide what arrangements to make with respect to resource adequacy. For example, some states might approve utility-level resource adequacy policies, or institute a state-level capacity construct, while other states might plan to remain under a modified RTO capacity construct for zones or consumers not eligible to opt out. Other states and load-serving entities might focus on educating consumers about the potential consequences of their choices, perhaps with backstop resource adequacy arrangements that would take effect only under very restricted circumstances.

2. Resource adequacy reporting requirements could be imposed on entities that elect to opt out of the RTO's construct. The consequences of any resource shortage event could potentially be linked to such reports. For instance, the rules for imposition of load drop and/or penalties might take into account entities' forward resource adequacy arrangements.
3. For the prompt time frame (months in advance of the delivery period) the RTO's capacity construct might remain mandatory for a longer period of time, providing residual procurement on behalf of any load-serving entities that have not self-supplied to meet their chosen targets. However, the goal should be to ultimately remove the mandatory aspect of the capacity construct.
4. As participation in the RTO's capacity construct becomes voluntary, participation by capacity sellers would also become voluntary, subject to the same prohibitions on market power and market manipulation that apply to all FERC wholesale markets. The potential for local market power would be evaluated during the transition period, and any problematic circumstances would be addressed, perhaps through transmission enhancements or mitigation agreements.
5. Consistent with the notion of a capacity spot market being transitioned to a voluntary construct, provisions that impose minimum offer prices or adjust prices for certain types of actions would be removed.
6. In the process of such a transition, states might also evaluate whether "one day in ten years" is still appropriate and meaningful as a resource adequacy target in a world in which advanced metering, demand response, price-responsive demand and energy storage will become increasingly widespread.[47] If remaining with the RTO's capacity construct, states might instruct the RTO as to the level of resource adequacy to be provided for in-state loads, and the procedures to apply under any circumstances of inadequate resources. A similar process can be used for the cooperative and public power utilities, who are not always regulated by the state commission.
7. This approach to resource adequacy would make the further development of energy and ancillary services markets even more important. The goal should continue to be for these markets to fully and accurately value all needed services and resource attributes.

VIII. Benefits of a More Decentralized, Voluntary Approach to Resource Adequacy

Transitioning to a maximally voluntary approach to resource adequacy would have the following benefits:

- Allows eligible customers, load-serving entities and states to pursue resource adequacy policies of their own selection, which may entail different adequacy targets.
- Accommodates different business models and capacity contracting approaches for both buyers and sellers, such as negotiated long-term bilateral contracts.
- Provides states and localities more flexibility to pursue policies such as promoting clean energy, energy efficiency, and retail competition.
- May result in new, innovative approaches to resource adequacy, for instance, with greater reliance on demand-side involvement in energy and ancillary services markets to ensure supply and demand balance without resorting to involuntary curtailment.
- Allows more accurate valuation of resource types and resource attributes as the industry resource mix changes, with greater emphasis on energy and ancillary services markets and bilateral long-term contracts, less on administrative capacity payments.
- Potentially provides stronger price signals for needed resource types and attributes such as fast-ramping ability, by reducing excess capacity and shifting cost recovery back to the energy and ancillary services markets that can accurately value such attributes.
- Minimizes state-federal jurisdictional conflicts by obviating the need for intervention in response to state actions that could affect wholesale spot market capacity prices.
- Reduces the need for frequent and often-contentious stakeholder processes around RPM design elements and parameters.
- Removes the grounds for the confusion and false hopes around RPM prices and price formation.
- Reduces the incentives for PJM and capacity sellers to promote changes to RPM's rules and parameters that lead to excess capacity.

IX. Conclusion

Administrative, years-forward capacity constructs such as RPM were conceived over a decade ago when the wholesale markets were relatively new to address concerns arising from shortcomings in the early market designs such as price caps and inelastic demand. RPM has been changed over time to help maintain conservative levels of capacity under various challenging conditions that have arisen. As a result of such evolution RPM has become much more complex and costly and further changes to its design continue to be controversial. It has become clear that the original, "commodity" vision of competitive wholesale power markets requires a highly administrative capacity construct with complex rules about price formation and resource offer prices.

The market design shortcomings that were believed to lead to "missing money" have largely been addressed, with strong shortage pricing rules and increasingly price-responsive and controllable demand. Meanwhile, the resource mix is changing with a greater variety of resources and broader range of important resource attributes, such as fast ramping ability, and more challenging attributes such as intermittence. The energy and ancillary services markets will be adapted to price such attributes, and forward bilateral contracts will reflect the anticipated value of resources and resource attributes. But capacity constructs, pricing a standard capacity product through administrative auctions creating a revenue stream subject to various administrative penalties, will only very inaccurately contribute to the forward valuation of such attributes. And chronic excess capacity prevents the short-term markets from accurately valuing new resources and resource attributes.

RPM, and other such capacity constructs, can be transitioned to a more voluntary basis through decentralization to states, utilities and load-serving entities, and by empowering end-use customers that so choose to be responsible for their supply arrangements. This will allow the industry to move away from the centralized, "public good" treatment of resource adequacy to approaches that more accurately and efficiently provide the types of resources and services desired.

Endnotes

1 See, for example, Hogan, William F., *Electricity Pricing Through Operating Reserves*, Economics of Energy & Environmental Policy Vol. 2 No. 2, 2013; Newell, Samuel et al (The Brattle Group), *ERCOT Investment Incentives and Resource Adequacy*, June 1, 2012.

2 Wilson, James F., *Reconsidering Resource Adequacy, Part 1: Has the One Day in Ten Years Criterion Outlived Its Usefulness?* Public Utilities Fortnightly, April 2010 (critiquing the widely-used criterion, under which the expected frequency of having to curtail firm load due to inadequate capacity should be no greater than once every 10 years).

3 See, for example, NERA Economic Consulting, *Central Resource Adequacy Markets for PJM, NY-ISO and NE-ISO*, 2003 ("CRAM Report").

4 The term "missing money" is attributed to Roy D. Shanker. See, for example, *Comments of Roy J. Shanker, Ph.D. on Standard Market Design: Resource Adequacy Requirement*, January 10, 2003 in FERC Docket No. RM01-12, p. 3.

5 In addition to PJM's Reliability Pricing Model, ISO New England implemented its Forward Capacity Market ("FCM") and NYISO implemented its Installed Capacity ("ICAP") Market.

6 To the extent the missing money is less for any one resource type at some time (say, peaking resources), investment would likely be focused on expanding that type of resource until the advantage was eliminated. Also see discussion in Hogan, William F. *On An "Energy Only" Electricity Market Design For Resource Adequacy*, September 23, 2005, p. 3.

7 This is discussed further in Wilson, James F., *Reconsidering Resource Adequacy Part 2: Capacity Planning for the Smart Grid*, Public Utilities Fortnightly, May 2010.

8 PJM deactivated over 21,000 MW of installed capacity from 2012 through 2015. The details are available at http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx

9 for a more detailed discussion of the RTO as an organization and its interests, see Felder, Frank A., *Watching the ISO Watchman*, Electricity Journal Vol. 25 No. 10, November 2012.

10 135 FERC ¶ 61,022, *Order Accepting Proposed Tariff Revisions, Subject to Conditions, and Addressing Related Complaint*, issued April 12, 2011 in FERC Docket Nos. ER11-2875, EL11-20.

11 146 FERC ¶ 61,052, *Order on Proposed Tariff Changes*, issued January 30, 2014 in FERC Docket No. ER14-504.

12 147 FERC ¶ 61,060, *Order Accepting Tariff Revisions*, issued April 22, 2014 in FERC Docket No. ER14-503.

13 149 FERC ¶ 61,183, *Order Conditionally Accepting Tariff Revisions Subject to Compliance Filing*, issued November 28, 2014 in FERC Docket No. ER14-2940.

14 Administrative Net CONE values have nearly doubled from $160.76/MW-day for 2011/12 delivery to $299.30MW-day for 2019/20.

15 PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, May 8, 2014, pp. 24-25.

16 PJM, *2015 Winter Report*, May 13, 2015, p. 5; 2016 Winter Report, May 31, 2016, p.1.

17 For more details on the Capacity Performance provisions, see PJM Interconnection, L.L.C., 151 FERC ¶ 61,208, June 9, 2015 (Capacity Performance Order).

18 Wilson, James F., *PJM's "Capacity Performance" Tariff Changes: Estimated Impact on the Cost of Capacity*, prepared for the American Public Power Association, October 2015.

19 Monitoring Analytics, *2015 State of the Market Report for PJM*, Table 5-23 p. 217.

20 PJM, *2019/2020 RPM Base Residual Auction Results*, p. 1 (noting the clearing price of $100/MW-day for the RTO region, and observing that it was approximately 33% of the administrative Net CONE value).

21 PJM, *Planning Parameters for the 2019/2020 base residual auction* (comparing Net CONE to gross CONE for the RTO region; for the Mid Atlantic region, the proportion is 67%).

22 See, for instance, FERC Chairman Norman C. Bay's dissent to the June 2015 order in the Capacity Performance proceeding, PJM Interconnection, LLC, 151

FERC ¶ 61,208 (Capacity Performance Order), (suggesting that the Capacity Performance proposal "may result in billions in additional costs for consumers without achieving its intended aim").

[23] See, for instance, Tabors, R., Parker, G., Centolella, P. and Caramanis, M., *White Paper on Developing Competitive Electricity Markets and Pricing Structures*, April, 2016, for a discussion of distribution level market platforms.

[24] NERA Economic Consulting, *Central Resource Adequacy Markets for PJM, NY-ISO and NE-ISO, Final Report*, February 2003 ("CRAM Report").

[25] CRAM Report, p. 3.

[26] Wilson, James F., *Forward Capacity Market CONEfusion*, Electricity Journal Vol. 23 Issue 9, November, 2010. See also Affidavit of James F. Wilson on Behalf of the Public Power Association of New Jersey, Docket Nos. ER05-1410 and EL05-148, October 19, 2005, pp. 15-17; Affidavit of James F. Wilson on Proposed Changes to the Reliability Pricing Model in Support of Protest of RPM Load Group, Docket No. ER09-412-000, January 9, 2009, PP 194-201.

[27] RPM base residual auctions have attracted new entry while consistently clearing well below administrative Net CONE values. See PJM, base residual auction reports, http://www.pjm.com/markets-and-operations/rpm.aspx. See also The Brattle Group, *Second Performance Assessment of PJM's Reliability Pricing Model*, August 26, 2011, p. 93 (acknowledging that new plants generally offer into RPM at a wide range of prices, and often at very low prices, rather than at Net CONE, and that "offers seem to reflect a wide range of different bidding, hedging, and market-timing strategies").

[28] For a more detailed discussion of what should, and should not, be expected from a capacity spot market, see Comments of James F. Wilson in FERC Docket No. AD13-7, *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators*, September 9, 2013, pp. 6-8.

[29] Revisions to RPM filed by PJM in FERC Docket No. ER14-1461-000, Mar. 10, 2014 ("Replacement Capacity Proceeding.") These changes were overtaken by the Capacity Performance effort.

[30] See, for instance, Wilson, James F., *Raising the Stakes on Capacity Incentives: PJM's Reliability Pricing Model (RPM)*, prepared for APPA, March 14, 2008, pp. 59-66.

[31] PJM, *2019/2020 RPM Base Residual Auction Results*, p. 1, 8 (noting the cleared quantity represented a 22.4% installed reserve margin, nearly two percent higher than the previous highs).

[32] In the probabilistic modeling used to calculate the required reserve margin, PJM represents its diverse neighbors as a single external zone, and limits the potential assistance from them to the administrative Capacity Benefit Margin, 3,500 MW, in addition to other conservative assumptions that understate the likely assistance. See PJM, *2015 PJM Reserve Requirement Study*, October 18, 2015, pp. 10-13.

[33] See, for instance, Wilson, James F., *Affidavit in Support of the Motion to Intervene and Comments of the Public Power Association of New Jersey*, FERC Docket No. EL15-83, July 17, 2015, Exhibit JFW-1.

[34] For further discussion of capacity demand curve shape, see Wilson, James F., *Affidavit in Support of the Protest of the PJM Load Group*, FERC Docket No. ER14-2940 (RPM Triennial Review), October 16, 2014.

[35] Newberry, David, *Missing money and missing markets: Reliability, capacity auctions, and interconnectors*, Energy Policy 94 (2016) (arguing that a bias toward excess capacity exacerbates the "missing money" problem).

[36] For a detailed discussion see, for instance, Milligan, M. et al, Wholesale electricity market design with increasing levels of renewable generation: *Revenue sufficiency and long-term reliability*, Electricity Journal vol. 29 (2016).

[37] For a detailed discussion of the history and problems around the minimum offer price rules, see Morrison, Jay, *Capacity Markets: A Path Back to Resource Adequacy*, Energy Law Journal vol. 37:1 2016.

[38] 135 FERC ¶ 61,022, *Order Accepting Proposed Tariff Revisions, Subject to Conditions, and Addressing Related Complaint*, issued April 12, 2011 in FERC Docket Nos. ER11-2875, EL11-20, P 143.

[39] PJM acknowledges that the PJM markets do not allow consideration of various public policy objectives, and that the market environment would be improved by more opportunities for longer-term contracting. See, for instance, letter to stakeholders from Andrew L. Ott, President and CEO, PJM, July 8, 2016.

[40] Electric Power Supply Association et al v. FirstEnergy Solutions Corporation et al, *Complaint Requesting Fast Track Processing*, FERC Docket No. EL16-34, January 27, 2016.

[41] NextEra Energy Resources, LLC and PSEG Companies v. ISO New England Inc. *Complaint and Request for Fast Track Processing*, FERC Docket No. EL16-93, June 24, 2016.

[42] *Hughes v. Talen Energy Marketing, LLC*, No. 14-614 (U.S. Apr. 19, 2016).

[43] CRAM Report at 5, 28, 31, 33.

[44] See, for instance, May 19, 2016 letter to PJM Board of Managers from Nicholas K. Akins, Chairman, President and CEO of American Electric Power Company, Inc., Charles E. Jones, President and CEO of FirstEnergy Corp., and others, suggesting (p. 2) that RPM's fundamental structure, with a one-year commitment established three years in advance, is a "primary flaw" that will "set consumers up for more volatility, less innovation, and ultimately, higher costs."

[45] Bessemer, T. and Shields, F., *Resource Investment in the Golden Age of Energy Finance*, report for the ISO/RTO Council, May 2015, p. 18 (stating that banks discount predicted capacity revenues 50% to 70% in evaluating investment propositions).

[46] See, for instance, Pfeifenberger, J.P. and Newell, S.A., *Trusting Capacity Markets*, Public Utilities Fortnightly, December 2011, noting that capacity market performance is questioned by many market participants, and that stakeholders have doubts that they can support investment.

[47] As one candidate approach, see Hung Po Chao, Shmuel Oren and Robert Wilson, Restructured Electricity Markets: A Risk Management Approach, July 1, 2005 (recommending a "Third Way" under which utilities retain responsibility for resource adequacy for small customers under performance-based regulation and a revised regulatory compact).

[48] There is a common misconception that the "one day in ten years" resource adequacy criterion is a requirement imposed by FERC, NERC (North American Electric Reliability Corporation), ReliabilityFirst Corporation, and/or some other authority. But there is no such rule or requirement. With respect to RPM, PJM proposed, and stakeholders accepted, use of the criterion. FERC has approved reliability standard BAL-502-RFC-02 applicable to PJM, which merely requires performing a study using this criterion, but requires no action based on the study (134 FERC ¶ 61,212, Order No. 747, Planning Resource Adequacy Assessment Reliability Standard, P. 23, P. 33). In approving BAL-502-RFC-02 to require a study using "one day in ten years", FERC explicitly stated that it need not determine whether this criterion is "the most effective or most economically efficient method", and it "does not establish the one day in ten years criterion to be the de facto, or the only acceptable metric for resource adequacy assessment." Order 747, P. 31. FERC also noted in Order 747 that the standard "does not touch the establishment of specific resource adequacy requirements, and thus does not intrude on the state's decisional authority with respect to building or acquisition of assets or capacity to meet resource adequacy needs." Order 747, P. 21.

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