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Operating Flexibility Analysis for R.12-03-014

Mark Rothleder, Executive Director, Market Analysis and Development

Shucheng Liu, Principal Market Developer

Clyde Loutan, Senior Advisor

Arne Olson , E3

CPUC, Workshop June 4, 2012

Step 3 of Proposed New Approach

- Test for flexibility within portfolio that comes from Step 2
  - Includes any resources added to meet reliability standard
- Need for ramping capability is not the same thing as need for new resources
  - Conversion of existing resources to something more flexible could solve a ramping problem without changing the PRM
- Stochastic component estimates the probability of having a ramping capacity shortage based on distribution of hourly ramps
  - Within-hour ramps also assessed through incorporation of Step 1 results
- PLEXOS runs to test operability of portfolio that comes from Step 3

Attachment F: Assembly Bill 1576 (Nunez), Stats. 2005

AB-1576 Electrical corporations: rates: repowering projects. (2005-2006)

Assembly Bill No. 1576

CHAPTER 374

An act to add Section 454.6 to the Public Utilities Code, relating to public utilities.

[Approved by Governor September 29, 2005. Filed Secretary of State September 29, 2005.]

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AB 1576, Nunez. Electrical corporations: rates: repowering projects.

Under existing law, the Public Utilities Commission (PUC) has regulatory authority over public utilities, including electrical corporations. Existing law authorizes the PUC to fix the rates and charges for every public utility, and requires that those rates and charges be just and reasonable. Under existing law, a public utility has a duty to serve, including furnishing and maintaining adequate, efficient, just and reasonable service, instrumentalities, equipment, and facilities as are necessary to promote the safety, health, comfort, and convenience of its patrons and the public. The Public Utilities Act requires the PUC to review and adopt a procurement plan for each electrical corporation in accordance with specified elements, incentive mechanisms, and objectives, including the requirement that the procurement plan enable the electrical corporation to fulfill its obligation to serve its customers at just and reasonable rates.

The existing Warren-Alquist State Energy Resources Conservation and Development Act establishes the State Energy Resources Conservation and Development Commission (Energy Commission) and requires it to certify sufficient sites and related facilities that are required to provide a supply of electricity sufficient to accommodate projected demand for electricity statewide. The act grants the Energy Commission the exclusive authority to certify any stationary or floating electrical generating facility using any source of thermal energy, with a generating capacity of 50 megawatts or more, and any facilities appurtenant thereto. Existing law, until January 1, 2007, requires the Energy Commission to establish a process for the expedited review of applications to construct and operate thermal powerplants and related facilities and for the expedited review of repowering projects, as defined.

This bill would require that the costs of a contract entered into pursuant to a procurement plan by an electrical corporation for the electricity generated by a replacement or repowering project concerning a thermal powerplant that meets specified criteria be recoverable in rates, taking into account any collateral requirements and debt equivalence associated with the contract, in a manner determined by the PUC to provide the best value to ratepayers.

Existing law requires the Energy Commission to prepare an integrated energy policy report every 2 years.

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Existing law requires the report to contain an overview of major energy trends and issues facing the state, including, but not limited to, supply, demand, pricing, reliability, efficiency, and impacts on public health and safety, the economy, resources, and the environment.

This bill would require the Energy Commission, in consultation with the State Water Resources Control Board, to include in the integrated energy policy report to be adopted November 1, 2007, a review of the progress made toward implementing certain performance standards adopted pursuant to the federal Water Pollution Control Act for electrical generating facilities requiring certificates from the Energy Commission.

Vote: majority Appropriation: no Fiscal Committee: yes Local Program: no

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The Legislature finds and declares all of the following:
SECTION 1. (a) It is in the public interest for the state's electricity generating facilities to provide clean, reliable, efficient, and affordable electricity to the state's electricity consumers.

(b) Certain existing electric generating facilities are strategically located and interconnected to gas transmission pipelines and the electric transmission system in a manner that optimizes their reliability, deliverability, their cost-effectiveness, and their ability to deliver electricity to load centers.

(c) Many of these existing electric generating facilities exhibit less than optimal environmental performance, reliability, and efficiency compared to facilities that have been more recently permitted to operate.

(d) According to the State Energy Resources Conservation and Development Commission, a number of these older, less efficient electric generating facilities are at a high risk of being retired in the next several years. As a result, their generating capacity, which establishes a valuable reserve margin for the state, helps to provide local reliability and voltage support, and alleviates transmission congestion, may no longer be available.

(e) Because of their strategic location and existing infrastructure, it is in the best interest of the state to encourage the replacement or repowering of these facilities.

(f) Investment in replacement or repowered electric generating facilities replaces our aging facilities with more efficient and cost-effective facilities that enhance environmental quality and provide economic benefits to the communities in which they are located.

(g) Therefore, it is in the public interest for the state to facilitate investment in the replacement or repowering of older, less-efficient electric generating facilities in order to improve local area reliability and enhance the environmental performance, reliability, efficiency, and cost-effectiveness of these facilities.

(h) An effective means for facilitating that investment, while ensuring adequate ratepayer protection, is to authorize electrical corporations to enter into long -term contracts for the electricity generated from these facilities on a cost-of-service basis.
(i) Contracts approved by the Public Utilities Commission and certificates approved by the Energy Commission for the replacement or repowering of older, less-efficient electric generating facilities should achieve improvements in environmental performance to the maximum extent practicable, including reductions in air emissions and water use and discharge, compared to the replaced or repowered facility.

SEC. 2. Section 454.6 is added to the Public Utilities Code, to read:

454.6. (a) A contract entered into pursuant to Section 454.5 by an electrical corporation for the electricity generated by a replacement or repowering project that meets the criteria specified in subdivision (b) shall be recoverable in rates, taking into account any collateral requirements and debt equivalence associated with the contract, in a manner determined by the commission to provide the best value to ratepayers.

(b) To be eligible for rate treatment in accordance with subdivision (a), a contract shall be for a project

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which meets all of the following criteria:

(1) The project is a replacement or repowering of an existing generation unit of a thermal powerplant.

(2) The project complies with all applicable requirements of federal, state, and local laws.

(3) The project will not require significant additional rights-of-way for electrical or fuel-related transmission facilities.

(4) The project will result in significant and substantial increases in the efficiency of the production of electricity.

(5) The Independent System Operator or local system operator certifies that the project is needed for local area reliability.

(6) The project provides electricity to consumers of this state at the cost of generating that electricity, including a reasonable return on the investment and the costs of financing the project.

SEC. 3. The State Energy Resources Conservation and Development Commission, in consultation with the State Water Resources Control Board, in the integrated energy policy report to be adopted November 1, 2007, pursuant to Section 25302 of the Public Resources Code, shall include a review of the progress made toward implementing the performance standards adopted by the Administrator of the Environmental Protection Agency pursuant to Section 316 of the federal Water Pollution Control Act (33 U.S.C. Secs. 13161 and 1326) for electrical generating facilities requiring certificates pursuant to Chapter 6 (commencing with Section 25500) of Division 15 of the Public Resources Code.

Attachment G: Pfeifenberger, Johannes , et. al., "Second Performance Assessment of PJM's Reliability Pricing Model: Market Results 2007/08 through 2014/15" The Brattle Group, August 26, 2011

The Brattle Group

Second Performance Assessment of PJM 鈫s Reliability Pricing Model

Market Results 2007/08 through 2014/15

August 26, 2011

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Prepared for

PJM Interconnection, L.L.C.

EXECUTIVE SUMMARY

The Brattle Group has been commissioned by PJM Interconnection L.L.C. (錂PJM 鐳) to evaluate the performance of its Reliability Pricing Model (錂RPM 鐳), as required periodically under the PJM tariff. The scope of our evaluation includes: (1) a review of all Base Residual Auctions (錂BRAs 鐳) and Incremental Auctions (錂IAs 鐳) conducted to date to assess RPM 鈂s effectiveness in encouraging and sustaining sufficient capacity investments for reliability; (2) stakeholder interviews to identify key areas of concern; (3) an engineering cost estimate of the Cost of New Entry (錂CONE 鐳) for each of five CONE Areas; (4) an evaluation of individual RPM design elements, including the Variable Resource Requirement (錂VRR 鐳 curve), the Energy and Ancillary Service (錂E&AS 鐳 offset) methodology, and other design elements identified by stakeholders; (5) a probabilistic simulation analysis of RPM 鈂s performance; and (6) development of recommendations for possible modifications to improve the effectiveness of RPM.

Our primary finding is that RPM is performing well. Despite concerns by some stakeholders, RPM has been successful in attracting and retaining cost-effective capacity sufficient to meet resource adequacy requirements. Resource adequacy requirements have been met or exceeded in both the Regional Transmission Organization (錂RTO 鐳) and, during the last four BRAs, in all of the individual Locational Deliverability Areas (錂LDAs 鐳) at capacity prices below the net cost of new entry (錂Net CONE 鐳). Year-to-year capacity price changes have been consistent with market fundamentals, reflecting changes in the supply and demand for capacity. RPM has reduced costs by fostering competition among all types of new and existing capacity, including demand-side resources. It has also facilitated decisions regarding the economic tradeoffs between investment in environmental retrofits on aging coal plants or their retirement.

Stakeholders have raised a number of key concerns. We find, however, that several major criticisms of RPM are contradicted by evidence available to date 霂 most notably the arguments that RPM prices are too high, that RPM does not support investment in new generation of the right types in the right places, or that RPM cannot maintain reliability in the face of environmental retirements. Stakeholders expressed particular concerns about the volatility and unpredictability of RPM prices. Some of the observed price changes are consistent with changes in market fundamentals, which necessarily must be reflected in prices for the market to be efficient. Others are caused by the one-time implementation of various improvements to the initial RPM design, such as modeling more LDAs or elimination of Interruptible Load for Reliability (錂ILR 鐳). These impacts on prices reflect a non-recurring one-time adjustment, which is not a concern going forward. However, price uncertainty remains high due to non-transparent, and possibly excessive, fluctuations in modeled transmission limits and other administratively-defined parameters in RPM. We thus recommend a number of refinements to make the determination of transmission limits and administrative parameters more stable and transparent. To increase forward price transparency and facilitate long-term contracting, we also support the development of voluntary auctions or an over-the-counter trading platform for long-term capacity products.

Finally, we have identified several performance risks stemming from the RPM design that should be addressed to ensure that resource adequacy will be met going forward. To address these concerns, we recommend the implementation of six safeguards that would mitigate the identified performance risks. First, we recommend calibrating the E&AS offset methodology to E&AS margins actually earned by generation plants similar to the reference technology, which may increase Net CONE in some LDAs. Second, we recommend raising the price cap of the VRR curve to mitigate under-procurement risks. The higher cap will avoid the collapse of the VRR curve following anomalously high E&AS margins, which could result in reserve margins that remain well below reliability requirements. The higher cap will also avoid deterring offers with costs that temporarily exceed the *current* cap due to large differences between actual and administrative Net CONE values. Third, we recommend modeling constrained LDAs more proactively for locations where significant amounts of plant retirements are likely.

Fourth, we recommend maintaining the 2.5% overall Short-Term Resource Procurement Target ("STRPT") for the total resource requirement, but eliminating the "holdback" for Annual and Extended Summer resources. Fifth, we recommend introducing audits of demand-side resources to confirm their contractual and physical ability to respond as often and seasonally as claimed. And finally, we recommend establishing exemptions to the Minimum Offer Price Rule ("MOPR") to better support competitive entry through bilateral and self-supply arrangements.

The report explains these and other more minor recommendations for possible refinements to the RPM design that could further improve market efficiency. It also summarizes the results of the CONE study we conducted, including our recommendations about the choice between levelization methods. The detailed engineering cost study is documented in our separate report, *Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM* ("CONE Report").

A. RPM AUCTION RESULTS TO DATE

RPM introduced a capacity market design based on three-year forward annual auctions for locational capacity, with supply offers clearing against a downward sloping demand curve (the VRR curve). RPM is designed to achieve resource adequacy, improve price stability compared to the previous capacity market construct, and force existing resources to compete with a potentially large supply of new resources.

We previously assessed the overall effectiveness of RPM in our 2008 *Review of PJM's Reliability Pricing Model (RPM)*, which documented RPM auction results for the first five delivery years; from 2007/08 through 2011/12. Since then, three more base auctions have been conducted; the latest in May 2011 for the 2014/15 delivery year.

Based on our analysis of all RPM auctions conducted to date, we present the following findings:

- RPM has attracted and retained sufficient capacity to maintain resource adequacy in the RTO and in all LDAs, in spite of environmental and other challenges faced by suppliers. All regions have demonstrated capacity supplies in excess of their reliability

We recognize that the full development and implementation of any of the above recommendations would likely require additional resources dedicated to PJM 銑s load forecasting function. However, given the importance and monetary implications of PJM 銑s load forecasting functions in terms of RPM and transmission planning, the incremental cost of these resource requirements will likely be small compared to the benefits. The benefits also include increased transparency, improved forecasting data and processes, and the economic benefits of being able to reflect a better understanding of long-term load forecasting uncertainty in PJM transmission planning and stakeholder investment decisions.

C. COMPARABILITY OF CAPACITY RESOURCE TYPES

One of the original objectives of RPM was to allow different capacity resource types to compete in meeting PJM 銑 resource adequacy requirements. To ensure that resource adequacy is achieved at the lowest cost, it is important to ensure that all resources capable of providing capacity can participate in RPM and that resources providing comparable capacity receive comparable treatment.

We find that PJM 銑s incorporation of multiple types of demand resources (DR) is one of RPM 銑s greatest successes. The successful integration of DR also helps to achieve resource adequacy at a lower cost. PJM has already addressed the two most important original design issues that arose as the amount of DR increased: (1) starting with the 2012/13 delivery year, it fully integrated DR into RPM by eliminating the ILR option; and (2) starting with the 2014/15 delivery year, it established differentiated DR products recognizing that DR that allows for only limited dispatch and has only seasonal availability has less capacity value than year-round availability of unlimited resources.

However, some stakeholders have emphasized that with DR approaching 10% of RPM-cleared capacity, including two new, untested products, the comparability of DR to other resource types should be reassessed. We thus evaluate: (1) the new multi-product construct to accommodate different types of DR resources; (2) existing mechanisms to verify and enforce that resources committed in RPM will perform as promised; (3) the determination of the (UCAP) capacity value for DR; and (4) potential future directions to recognize the capacity value of other non-traditional resources.

We find that PJM 銑 existing design largely addresses stakeholder concerns. However, we recommend some refinements to further improve the efficiency of RPM and to ensure that all resources can perform as claimed. Our primary recommendation is to consider expanding the resource registration process just before each delivery year to include audits of random samples of contracts and the nature of loads that will be reduced. Annual DR resources must be able to respond in all seasons and not be constrained by contractual limitations on the number of calls. Extended Summer resources must also be unconstrained in the number of calls. This will allow PJM to confirm that resources can respond as frequently as claimed. Such verification and potential deficiency penalties will provide strong incentives to DR providers to make their offers and commitments consistent with ultimate capabilities. However, since only a small fraction of DR committed in the 2014/15 auction cleared as Annual or Extended Summer DR, this mostly addresses a potential concern about commitments made in future auctions.

1. Multiple Products to Accommodate Different Types of DR

In response to the rapid growth of DR in RPM, PJM recently conducted a demand response saturation analysis[154] that assessed the impact of Limited DR in replacing year-round (annual) generation capacity at a relatively large scale.[155] The primary concern was that extensive reliance on Limited DR 霖which can be curtailed no more than ten times a year, for only up to six hours during each event, and only during the summer months 霖could lead to reliability problems. As DR displaces larger amounts of generation capacity, it could be needed to curtail more often, for longer durations, or during months when Limited DR is not obligated to curtail. This was not a concern at low levels of DR penetration because the chance that a DR resource would be called more often than its capacity obligation allows was very small. PJM 鈥檚 DR saturation analysis indicated that reliability problems were likely if PJM continued to rely on Limited DR at higher levels of penetration.[156]

There were several options available to address this concern. One was to redefine the obligations of DR from a limited (10x6) capacity resource to an annual resource by requiring them to be ready and available during the entire delivery year, just like generation capacity committed under RPM.[157] Another option was to retain the Limited DR resource type while adding a new, unlimited DR resource type. PJM opted for a hybrid approach to resolve the identified reliability risks by adding two new DR resource types starting with the 2014/2015 delivery year: Annual DR and Extended Summer DR. Although these products can be called upon more often than the Limited DR, neither of the two new products must be available at all times. Extended Summer DR is required to be available every day during a six-month extended summer period, May through October (compared to up to 10 times from June through September for Limited DR) and must be able to maintain load curtailments for up to 10 hours per event (compared to up to 6 hours for Limited DR). Annual DR must be available every day of the delivery year except during PJM-approved maintenance outages. The duration of events during which it must respond is limited to 12 hours from May through October, and to 15 hours from November through April. Annual resources include the newly-defined Annual DR and other annual resource types which are generally required to be available at all times, such as generation, but also energy efficiency. Extended Summer resources include all Annual resources and the newly-

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[154] PJM Interconnection, L.L.C., Exhibit 1 of the Tariff filing to FERC in Docket No. ER11-2288-000, submitted on December 2, 2010 and approved by FERC on January 31, 2011.

[155] Prior to the 2014/15 delivery year, the RPM design recognized only one type of DR that had limited obligations both in terms of the frequency, duration, and the timing of events during which it was required to respond. In the remainder of this section we refer to this resource type as 鍍Limited DR 鎦.

[156] PJM 鈥檚 analysis found that, at a 90% confidence level, the penetration of Limited (10x6) DR should not exceed 4.7% of peak load, in order to ensure that PJM would not need these resources more often, or request longer curtailments, than their obligation. An earlier analysis conducted by PJM found that reliability would not be affected at DR penetration below 7.5% of peak load, however that study was conducted using less sophisticated tools and analytical methods.

[157] This approach is favored by PJM 鈥檚 Independent Market Monitor, arguing that 鍍the potential benefit of an unlimited demand-side product will not be realized without the elimination of the current flawed DR product. 鎦 See Monitoring Analytics LLC, *2010 State of the Market Report for PJM*, page 118. This approach has also been implemented in other markets. For example, in ISO New England 鈥檚 Forward Capacity Market, demand resources must provide an annual capacity product (although they can combine with complementary resources).

defined Extended Summer DR (*i.e.*, all resources that must be available at least as often as Extended Summer DR).

The new design ensures that an adequate amount of Annual and Extended Summer resources is procured in RPM by setting a minimum amount of these two types of capacity that must be procured for the RTO and each LDA in each base auction.[158] The auction clearing mechanism treats the two new minimum capacity constraints in a similar manner as it treats transmission constraints (*i.e.*, to clear a minimum amount of local capacity). DR that qualifies as two or more of the DR types may submit separate but coupled offers for each DR type.[159] The auction clearing algorithm selects the offer that yields the least-cost overall capacity procurement. It will choose resources out of merit order if any of the minimum capacity constraints is binding. Prices may rise to clear additional Annual or Extended Summer DR, if needed, and those higher prices will be awarded for Annual and Extended Summer resources, but not for Limited DR. The price adders for Annual and Extended Summer resources reflect the additional value of unforced capacity required to meet the minimum capacity requirements. As a result of the recent market design change, price separation in RPM can now occur not just by location but also by resource type.[160]

PJM held its first BRA under the new design in May 2011 for the 2014/2015 delivery year. The auctions appear to be working as planned. In the auction, more than half (9,253 MW) of all DR resources submitted linked offers as Annual DR with an unlimited number of calls. Only 511 MW of Annual DR offers cleared, and 1,441 MW of Extended Summer, and 12,166 MW of Limited DR.

Overall, we conclude that the recently implemented change to the RPM market design was a reasonable and effective solution to a valid concern. However, the introduction of multiple capacity products for DR raises the question whether other kinds of resources should be allowed to be classified by product type. In this context we offer the following recommendations:

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158 The minimum amounts of Extended Summer resources are derived from the Reliability Requirement (reduced by the 2.5% Short-Term Resource Procurement Target) minus the maximum reliable amount of Limited DR. The maximum reliable amount of Limited DR is determined in a probabilistic analysis that identifies the level of DR where the probability that PJM will require 10 or more interruptions is less than 10% and the chance that it would require interruptions longer than six hours is relatively low. A similar analysis is used to establish the minimum amount of Annual resources and maximum reliable amount of Extended Summer resources. The maximum amount is the level of DR penetration at which the annual LOLE is 10% higher than the LOLE of a reference scenario with DR penetration of zero.

159 In other words, a single resource may have up to three linked offers, one each for Limited, Extended Summer, and Annual DR, but only one of those offers may clear in the auction.

160 PJM鈥檚 Independent Market Monitor disagrees with some aspects of the new design, namely the introduction of the Extended Summer DR product and the retention of Limited DR, which it views as a 鈥渇lawed鈥 capacity product. The IMM argued that reliance on Limited DR may compromise reliability and the overall capacity market design, and the addition of new DR products adds unnecessary complexity and creates an illiquid market for these products. Protest of the Independent Market Monitor for PJM, filed with FERC in Docket No. Docket No. ER11-2288-000 on December 20, 2010.

* ***Reclassifying Energy Efficiency based on capability.*** Energy efficiency is currently considered an annual product,[161] even though it is providing load reductions during a limited period.[162] We recommend that PJM consider reclassifying energy efficiency based on the periods when it can actually perform. For example, while energy efficient lighting would be an Annual resource, more energy efficient air conditioners could be classified as Extended Summer rather than Annual resources.

* ***Allow for Seasonal Generation.*** Generation capacity with seasonal (summer-only) availability cannot participate in RPM, because generators must offer an annual product. We recommend that PJM consider allowing such generation to participate as Limited resources. PJM could also consider allowing all generation that is submitting offers as Annual resources to also submit lower-priced linked bids as Limited capacity, reflecting the lower costs of committing the unit for the summer only.

2. Assurances of DR Performance

Forward capacity markets need to have mechanisms in place to ensure that committed resources, both existing and planned at the time of the BRA, will be available during the delivery year to fulfill their capacity obligations. Existing generating resources may face the risk of costly environmental retrofits or other major unexpected capital expenditures to stay online. Planned generation or demand-side resources face the risk of unexpected cost increases or delays. Untested products face the additional risk that actual circumstances during which they have to respond may be very different from what is currently expected. In this section, we focus on DR performance because of its high recent growth, but also to address stakeholder concerns about whether DR capacity is comparable to generation. More specifically, our primary focus is to explore whether existing measures will ensure that: (1) CSPs have sufficient incentive to submit realistically achievable DR plans; and (2) CSPs face sufficient verification and penalties if they were to misrepresent limited resources as unlimited resources.

PJM already has several stages of verification—including qualification, tracking development, registration, and performance and testing—and penalty and incentive mechanisms in place. There are several stages to validate the quality of new capacity resources and to assess the likelihood that they will be able to perform as expected during the delivery year. These stages include qualification of resources for the BRA, tracking the whether committed resources achieve various milestones prior to the delivery year, and penalizing resources for under-performance during the delivery year. We reviewed the milestones that planned resources in RPM must meet to avoid penalties due to non-compliance with their capacity obligations.

Table 1 Table 25 below summarizes each of these milestones for planned DR, actions taken by PJM at each milestone, as well as potential enhancements to the current process, as discussed below.

[161] PJM Tariff, Attachment DD, Section 2.1B.

[162] The performance hours for energy efficiency are between hour ending 15 Eastern Prevailing Time (EPT) and the hour ending 18 EPT from June 1 through August 31, excluding weekends and federal holidays. See Section 1.20A and Schedule 6 of the PJM Reliability Assurance Agreement.

a. Qualification

All resources must meet the qualification requirements for the BRA no later than approximately two weeks before the auction. For planned DR, this process consists of a review of the resource provider’s DR plan and the posting of credit. A DR plan consists of basic information about the project, such as the aggregator’s plan to procure customers, project milestones, and the nominated DR value, including the underlying assumptions used to derive it. Since these resources do not exist at the time of the auction, the evaluation of DR plans must be based on the credibility of the plan. It is important to ensure the process of reviewing DR plans is effective. However, we did not identify any potential enhancements for this stage of verification.

b. Tracking the Development of New Resources

The next stage is the tracking of new resources committed in RPM, which takes place between the BRA and the start of the delivery year. PJM may verify that a planned DR adheres to its DR plan at any time, but there is no pre-determined schedule of required progress reports. Furthermore, there appear to be no penalties for not following the DR plan. In contrast, ISO New England requires regular quarterly updates, and planned resources experiencing delays risk losing their posted credit and their capacity obligation if the planned online date moves beyond the start of the delivery year due to the delay.[163] We recommend introducing ***periodic update requirements from planned resources*** (*e.g.*, just before each incremental auction) as this would provide a clear indication whether planned resources are on track to be completed by the start of the delivery year.

c. Registration in Emergency Load Response Program

Registration in PJM’s Emergency Load Response Program is the final step before the delivery year. It must be completed and approved before the start of the delivery year to avoid deficiency penalties. As part of the registration process, customer-specific data (*e.g.*, peak load contribution) must be provided to PJM. The registration process is largely an administrative step and does not involve any verification by PJM of the resource’s ability to perform.[164] Since at this step planned resources must be at their final stage of development—with actual end-users and contracts in place—we recommend that PJM ***consider verifying that the CSP has the physical or contractual capability to curtail as often and seasonally as required***. For example, we believe that air conditioning load and event-limited contracts should not be able to register as Annual DR (given that no curtailments can be provided outside the air conditioning season), except perhaps as a discounted part of a larger, sufficiently balanced portfolio. Although DR resources are required to test during the delivery year, those tests do not check how frequently a resource would be able to curtail if called frequently or across seasons.

This is the most important enhancement we recommend. Adding such verification (and the threat of deficiency penalties) would provide additional incentives to CSPs to make sure their programs meet required capabilities. A comprehensive audit of all DR contracts may be too burdensome, but PJM could select a random sample for contractual audits (*e.g.*, a CSP’s

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[163] ISO New England Market Rule 1, Section III.13.3.4.

[164] Although PJM does not currently verify resources ability to perform in the registration process, EDCs and LSEs review DR programs to ensure that the customer physically exists and is not double counted.

portfolio of resources in a single zone). PJM could address audit failures by applying penalties (*e.g.*, deficiency penalties to the CSP’s entire PJM-wide portfolio) and/or referring the CSP to FERC.

Table 25
Verification of Planned DR

Activity	Timing	Assurances & Verification in Place	Potential Enhancements
Qualification of New Resources	At least 15 days prior to an RPM auction	**Review of DR Plan (** project description; customer recruiting plan & milestones; MW value of DR; key assumptions) **Verification of RPM Credit Limit** “**Provisional approval**” of DR MODs (assigns nominated value to individual resources) if above requirements are met	None identified.
Tracking	Anytime between BRA and delivery year	**Verify adherence to the schedule in the DR plan** at PJM’s discretion at any time including, but not limited to, 30 days prior to each IA; mostly relies on suppliers to develop planned resources and manage deficiencies by procuring replacement capacity (else risk penalties).	Consider requiring CSPs to periodically report their progress against DR plans.
Registration in Emergency Load Response Program	January through May prior to delivery year	Requires submittal of some customer-specific information Must be in “Approved” status prior to start of DY to avoid commitment shortfall & Deficiency Charge	**Introduce random audits of contracts and physical loads** to verify zonal resource portfolio abilities to curtail as frequently and seasonally as represented (esp. for Annual and Extended Summer), with appropriately punitive penalties to incent CSPs to represent accurately.
Performance & Testing	During delivery year	**Penalty/credit** for under-performance during emergencies (Load Management Events) **Penalty** for failing tests, but CSPs initiate tests; can test repeatedly and submit the best results. Tests show MW but not ability to respond frequently or seasonally.	**Conduct random testing initiated by PJM**; limit CSPs’ ability to selectively pick test results; extend duration of tests to multiple hours, *e.g.*, 6; provide energy payments during tests.

d. Performance Assessment and Testing during the Delivery year

The pre-auction validation process is followed by performance assessment and testing during the delivery year. Under normal, expected conditions, there may not be many actual load management events called in the delivery year. This limits PJM’s ability to discover how DR resources (or portfolios) would perform under unexpectedly tight market conditions (*e.g.*, due to an extended heat wave and major plant outages) when their capacity is most needed and calls are more frequent. To prevent CSPs from overstating their capabilities, we recommend a more rigorous verification process prior to (and possibly also during) the delivery year as discussed above.

Performance verification during the delivery years is also important. In case there are no dispatch events at all, testing is important for verifying that CSPs can produce the total committed number of MW in each zone in a single call. The current testing process works as follows: DR providers are required to conduct a one-hour simultaneous test of all their resources in a zone if PJM does not otherwise initiate an actual load management event in that zone. They are allowed to choose the timing of the test, as long as it falls within the hours of the summer period when the resources are obligated to respond, and notify PJM 48 hours in advance. If less than one quarter of the resources fail a test, the provider is allowed to retest the subset of resources that failed. There is no current limit on the number of tests that may be conducted, and the provider can submit the single most favorable of all the test results.

The fact that CSPs may conduct an unlimited number of tests and submit only the results for the test of their choosing raises the concern that those tests results may not reflect the resource’s actual ability to respond on a consistent basis. Therefore, we recommend that PJM ***consider adding random PJM-initiated tests to the current testing procedures, and limit CSPs’ ability to selectively pick the test results***. Furthermore, we recommend ***extending the duration of the tests to a multi-hour period***, consistent with the fact these resource are required to respond for a period of several consecutive hours.

e. Comparability of Penalty Mechanisms

Performance needs to be supported by penalties for under-performance. Such penalties should ensure that suppliers have the incentive to make resources available and guarantee their performance during the delivery year. Comparability of obligations and penalties across resource type also ensures that the different resource types compete on a level playing field.

PJM has two general types of penalties. A supplier is subject to a *deficiency penalty* if it is unable to provide all or part of its committed capacity in time for and during the delivery year. *Performance penalties* apply when the supplier’s committed resources do not perform adequately when called upon. Performance can be measured by various metrics during peak periods, testing, or other PJM-initiated events. Table 26 below compares penalties applicable to DR to those applicable to generation resources.

The penalties in Table 26 are grouped into the following categories: deficiency, availability, test failure, and other. Each penalty is decomposed into two components: (1) basis for penalty (for failing to meet a certain obligation, usually not providing the committed UCAP MW); and (2) the penalty rate, which is the rate at which an unfulfilled obligation is penalized (usually in terms of $/MW-day or $/event).[165] The Daily Deficiency Charge, which is the higher of 120% of the resource clearing price or the resource clearing price plus $20/MW-day, is the penalty rate for failing to meet several obligations, including capacity deficiencies, peak-season maintenance, and resource tests.

[165] Some charges can turn into a credit if the resource over-performs; thus they penalize under-performance while incentivize good performance.

Table 26
Comparison of RPM Penalties for Generators and DR & ILR

[illegible]			
[illegible]	Daily shortfall between committed and actual capacity	Wtd Avg RCP[1]+ Max[0.2*Wtd Avg RCP; $20/MW-day] *(Daily Deficiency Rate)*	N/A
Availability Penalties			
[illegible]	UCAP shortfall due to unapproved maintenance or planned outages during peak season	Wtd Avg RCP + Max(0.2 Wtd Avg RCP; $20/MW-day) *(Daily Deficiency Rate)*	N/A
[illegible]	Daily Net[3] Peak-Hour Period Capacity Shortfall (max. to a cap that gradually increases from 0.5 * UCAP to1 * UCAP by the third consecutive year of limited availability)	Wtd Avg RCP	N/A
[illegible]	Under-compliance (positive difference between committed MW and actual load reduction) during Load Management events[4]	N/A	*On-peak periods*: Min [(1/(# of events); 0.5] * Wtd Avg Annual Revenue Rate[5] *Off-peak periods*: 1/52 * Wtd Avg Annual Revenue Rate
Test Failure Penalties			
[illegible]	Shortfall between committed and tested capacity	Wtd Avg RCP + Max(0.2 Wtd Avg RCP; $20/MW-day) *(Daily Deficiency Rate)*	
Other Penalties			
[illegible]	Failure to comply with PJM instructions during emergencies	Number of days in the DY x Daily Deficiency Rate x Under-compliance MW	
[illegible]	Failure of existing generators to offer into a BRA	Not allowed to participated in any incremental auction or be used to satisfy any LSE 鈥s UCAP obligation; further action by IMM	N/A

Notes:
[1] Weighted average Resource Clearing Price of a portfolio in an LDA across all RPM auctions.
[2] The amount collected in Peak-Hour Period Availability penalties is credited to re source providers with negative net capacit y shortfalls, subject to cap of Net Peak-Hour Period Capacity Shortfall times their weighted average RCP in the LDA.
[3] The netting of Peak-Hour Period Capacity shortfall is performed across committed units by seller (*i.e.*, single eRPM account) in an LDA. Uncommitted capacity by the same seller may be used to offset shortfalls by committed capacity (provided uncommitted capacity is in the same LDA).
[4] Performance is assessed on a portfolio-basis by each seller in a given zone.
[5] Annual Revenue Rate is the RCP from the RPM auction where the resource was committed.

We conclude that penalty rates for DR and generation are comparable, with only a few exceptions noted below. They are now more comparable than in the early RPM design when, for example, when DR was not subject to test failure penalties and ILR was not subject to deficiency penalties due to its timing.[166] Some penalties, namely the peak-hour availability and peak-season maintenance compliance penalties apply only to generators. The rationale could be that DR is an idiosyncratic resource with availability that may be difficult to measure.

3. UCAP Value of DR Products

In order for DR resources to participate in RPM, they must be assigned an unforced capacity (UCAP) value. However, the traditional availability metrics used to calculate UCAP for generation are not necessarily applicable to DR because the nature of loads underlying DR is much more varied than the capacity of generation technologies. Therefore, the UCAP value of DR must be measured differently. The current method used in RPM is to multiply the nominated value of DR by the Forecast Pool Requirement (“FPR”) and the DR Factor.[167] The FPR grosses up the nominated value of DR for reserves (in UCAP terms) based on the rationale that if DR commits to be curtailed then PJM will not need to procure reserves for the underlying load — as if the load reduction were a reduction in the peak load forecast whose magnitude is perfectly correlated with system load. The DR Factor is based on the Effective Load Carrying Capability (“ELLC”) of the resource and accounts for the fact the resource may not always be available to serve PJM’s capacity needs.

The current method of calculating UCAP value for DR seems slightly inaccurate in different ways for each type of DR. A more accurate method would result in a UCAP value that better reflects the reduced capacity need as a result of the load curtailment. The method of calculating the UCAP value of DR should take into account the type of load curtailment that the resource is committed to provide. DR that commits to curtail load *by a given amount* under the Guaranteed Load Drop (GLD) option is very similar to generation, and therefore it should be assigned a comparable capacity value, without any need for adjustment using the current DR Factor and FPR Factor.

However, DR that commits to curtail load *to a pre-determined level* under the Firm Service Level (“FSL”) option provides greater value and should be assigned a higher UCAP value accordingly. The following example illustrates this point. Suppose a customer whose load is perfectly correlated with the system load has a 100 MW coincidental peak load forecast (all figures are assumed to be at the bus-bar level, already grossed up for the metered load for transmission losses). PJM will need to procure 108 MW of UCAP for this customer, assuming a typical FPR value of 108%. However, if the customer agrees to curtail its load to 90 MW whenever PJM calls on it under the FSL DR option, only 90 MW of UCAP is needed to serve the customer. Since this reduces the capacity need by 18 MW, the DR should be assigned a capacity value of 18 MW, ignoring unavailability. However, if the customer is not under supervisory control or is not able to curtail under all circumstances, the full 18 MW may be excessive. For example, if a customer’s *forecasted* load were reduced to 90 MW, without a guaranteed curtailment to that level, then the value of that load reduction would be 10.8 MW (change in load forecast multiplied by an FPR of 8%). Thus, even in that worst case, FSL-type DR should be assigned a UCAP value that continues to be grossed up by the FPR Factor, but without the

[166] Penalties will become even more comparable after the ILR option is eliminated starting with the 2012/2013 delivery year.

[167] Nominated value of DR is determined by the resource owner, and is akin to ICAP for generation.

discount currently applied through the DR Factor. The assigned UCAP value could be even higher for FSL under firm supervisory control.

As a separate issue, PJM's current method of determining UCAP value of existing DR ignores past performance, in contrast with UCAP value of generation. For generation, a one-year average EFORd is used to calculate its UCAP value for each delivery year. If the resource under-performs in previous years, its EFORd and UCAP value will reflect that fact. Therefore, generators are implicitly penalized for past weak performance. It would be reasonable to add a comparable adjustment to the UCAP value of DR resources. Unlike generation, capacity of DR depends more on the CSP's ability to manage its portfolio that on the quality of the underlying resource. Therefore it is should be assumed that if a CSPs portfolio underperformed in the past, it is likely to underperform in the future. This assumption could be maintained until the CSP proves otherwise. If a shortfall occurs due to derated DR capacity, replacement capacity can be procured in the incremental auctions.

4. The Present Proceeding Affecting GLD Value and Participation

PJM and its Independent Market Monitor recently identified an issue regarding the Guaranteed Load Drop ("GLD Option") used for measuring the performance of DR that chooses this method.[168] The key issue in this "double-counting" debate is how to measure compliance against the nominated (and committed) amount of DR and what should be the appropriate reference point or baseline. PJM has argued that allowing DR to measure its performance against a baseline that depends on recent load levels (effectively, the same baseline as the one used in the energy market) may provide an incentive for curtailment service providers to include assets in their portfolios with little ability to perform because over-performance by other assets in the portfolio will often allow the portfolio to perform at the expected level.[169] PJM analysis has indicated that this issue could result in the commitment of a large number of low-quality DR which could lead to future reliability problems. For example, during super-peak hours high-quality DR resources may be able to perform (*i.e.*, curtail to their peak load contribution, or "PLC") but not over-perform, while low-quality DR may under-perform. As a result, PJM may be, on aggregate, short on capacity when the amount of low-quality DR is relatively large. To address this, PJM has filed its proposal with FERC that would cap the baseline under the GLD option at each resource's PLC.

We are not commenting on the overall merits of PJM's proposal because it is being addressed in a separate proceeding, and we have not analyzed the need for PJM's proposal or its implications. However, we acknowledge stakeholder concerns that limiting DR contributions to reductions below a customer's PLC could impair the GLD option for some end users. End-users with a highly variable and unpredictable total load can often and legitimately experience unrestricted total load in excess of their PLC (which is based on peak loads during the year prior to the delivery year). Thus, they may not be allowed to fully take credit even for definitive actions to shed a portion of their load, such as

[168] PJM Filing to FERC in Docket No. ER11-3322-000 on April 7, 2011.

[169] DR performance is assessed on an aggregate basis for the provider's zonal portfolio. PJM explains that some of the over-performers are end-users that manage their super-peak loads and thus have low PLCs. They can provide additional reductions in non-super-peak hours, but not in the super-peak hours. Thus, they can over-perform (beyond their registered capacity) and cover for under-performers if events are only called outside of the super-peak hours.

interrupting a particular baseload process or turning on a backup generator. Such guaranteed load drop is valuable for RPM. If PJM's proposal is adopted, it will be important to fully preserve the GLD option in some manner.

Relatedly, some stakeholders have expressed concerns regarding the accuracy of PLC to measure each customer's contribution to the total capacity need. PLC is currently calculated by EDCs, usually based on the 5-CP method, which measures loads during the five highest zonal coincident peak hours during the summer before the delivery year. This method does not take into account the fact that capacity need arises outside the 5-CP hours, and some customers may find it relatively easy to avoid paying for any capacity by curtailing their load during just the super-peak hours that are likely to define the 5 CP. Therefore, we recommend that PJM ***consider working with the EDCs to refine their PLC methods***. Doing so would improve customers' incentive to more efficiently manage their load, and it would make PJM's proposed refinements to the GLD option less restrictive.

5. Future Directions

Future directions of RPM should include the incorporation of further resource types, in particular price responsive demand ("PRD") and advanced energy storage devices.

PJM recently presented its stakeholders with a proposal to integrate PRD into RPM. This proposal fits into a longer-term vision where PRD could play a more prominent role in electricity markets. In the long run, adding PRD will reduce the amount of generation capacity needed. By allowing LSEs to explicitly reduce their capacity obligations for expected PRD, capacity procurement costs also could be reduced. There have been competing PRD proposals, including one that PJM recently presented to its stakeholders.[170] The key (positive) elements of this proposal included PRD under supervisory control that commits to curtailments to a pre-determined level (Maximum Emergency Service Level) during PJM-declared emergencies, as well as a complementary scarcity pricing mechanism that would allow energy prices to rise above the current ($1,000/MWh) offer cap.[171] PJM and stakeholders should strive to complete the integration of PRD into RPM.

Another recent development has been the increased need for energy storage caused by the development of variable generation, especially wind. A range of advanced energy storage devices (such as, batteries, flywheels, thermal and compressed air energy storage, *etc.*) are currently under development. Although the primary driver behind the development of these devices is to provide additional ancillary services to balance the grid, these resources could also participate in RPM.

Energy storage devices have unique limitations that require a different methodology to calculate their capacity values. Storage devices may be able to provide two types of capacity products: (1) an annual product, for devices that can sustain their capacity value for at least 10 hours; and (2) a limited product for devices that can sustain their capacity value for at least 6 but less than 10

[170] PJM Staff Whitepaper, Price Responsive Demand, March 3, 2011.

[171] This is important because most loads have a higher reservation price, and low energy market offer caps would exclude them.

hours. We do not recommend adding any new capacity products for such a small category of potential capacity resources (compared to DR, for example) as that would make the RPM design more complex with questionable net benefits. Instead, to achieve the requirements of existing capacity products, multiple short-duration storage devices may need to be aggregated (*e.g.*, to reach 6 hours discharge capability) and mechanism would need to be developed to avoid recharging during dispatch periods.

6. Summary of Recommendations

We find that PJM 鈂s existing design mostly addresses identified stakeholder concerns, but we recommend that PJM and its stakeholders consider some refinements to further improve the efficiency of RPM and to ensure that all resources can perform as claimed.

With respect to the use of multiple capacity products to ***accommodate different resource types*** we recommend that PJM:

- Consider allowing other resource types with limited availability (*e.g.*, generation with seasonally-differentiated capabilities and costs) to make linked offers as Limited or Extended Summer resources.
- Consider re-classifying some seasonal resources (*e.g.*, energy efficient air conditioning) from Annual to Extended Summer.

With respect to the ***assurances of performance***, we recommend the following enhancements for PJM 鈂s consideration:

- ***Tracking***: continue to rely on suppliers to manage potential deficiencies to avoid penalties; however consider requiring Curtail Service Providers (錂CSPs 鎦) to periodically report their progress against planned milestones to increase visibility into progress and avoid surprises.
- ***Registration***: Introduce random audits of contracts and physical loads to verify zonal resource portfolio abilities to curtail as frequently and seasonally as represented (especially for Annual and Extended Summer), with appropriately punitive penalties to incent CSPs to represent accurately. These audits should be conducted before the start of the delivery year (when all 錂planned 鎦 resources have become actual resources involving end-users with contracts to curtail) or any time during the delivery year. This enhancement is our most important recommendation regarding DR even though little DR has yet cleared as Annual or Extended Summer resources.
- ***Testing***: conduct random tests and limit DR providers 鈂 ability to selectively choose the most favorable of (multiple) tests that. Tests should be called by PJM, and the duration of each test should be longer than one hour.

We recommend that PJM also consider slightly modifying its ***methodology for determining DR UCAP values***, in the following manner:

- ***FPR and DR Factor*** : Eliminate both the FPR and the DR Factor for GLD-type DR, counting guaranteed load reductions at its full value (just like generation); for FSL-type DR, eliminate the DR Factor and maintain the FPR gross-up (or more).
- ***Derating capacity values for weak performance*** : Derate future UCAP value of any resource (or a CSP portfolio) that under-performs during the most recent delivery years. Such derates already apply to generators as their average EFORd is lowered by past under-performance.

* ***Measurement and verification***: PJM should consider working with the EDCs to improve their methodologies for assigning PLCs, for example, by considering more hours than just the top five hours of the previous year.

Other recommendations:

* ***Price Responsive Demand (鍍PRD鑕)***: PJM and its stakeholders should integrate PRD into RPM by finalizing the proposal that PJM has already proposed.

D. 2.5% Short-Term Resource Procurement Target

1. Background

Substantial concerns have been raised by several stakeholders about the 2.5% short-term resource procurement target (STRPT). This 2.5% 鍍holdback鑙 is a quantity of capacity held back from the 3-year forward procurement. The amount is subtracted from the BRA VRR curve and therefore not procured in the base auction. Instead, that capacity is procured over the following three years, with 0.5% procured in the first incremental auction two years prior to the delivery year, 0.5% in the second incremental auction one year prior to the delivery year, and 1.5% in the third incremental auction, just prior to the delivery year.[172] Starting with the BRA for the 2014/15 delivery year, the holdback has been subtracted not only from the VRR curve, but also from the Minimum Annual and Minimum Extended Summer resource requirements.[173] The result of this approach is that the STRPT quantity held back is Annual capacity, which means the resources procured in the incremental auctions for the 2014/15 delivery year will be primarily for Annual capacity.[174]

The STRPT was first implemented for the 2012/13 delivery year at the same time that Interruptible Load for Reliability (ILR) was eliminated and DR resources were first required to bid and clear through the centralized auctions. Prior to the incorporation of DR into RPM auctions, demand-side resources were allowed to participate as ILR, which could register just prior to the delivery year but still receive the BRA price.[175] To account for that, the base auctions included a 鍍holdback鑙 for an amount of capacity equal to the forecast quantity of ILR for the delivery year (an amount that would not actually be known until the delivery year). When the ILR mechanism was eliminated, the STRPT replaced the ILR-related holdback and was introduced primarily to accommodate demand-side resources that had never before had to make three-year forward commitments.[176] Eliminating ILR and implementing the STRPT to

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[172] Other adjustments to reliability requirements and locational import limits are also reflected in these incremental auctions, including the incremental uncleared portion of the VRR curve and adjustments due to changes in load forecasts, see PJM (2011d), pp. 20-21.

[173] See, for example, the calculation of the Extended Summer and Annual resource procurement targets as a function of the STRTP for the 2014/15 BRA, PJM (2011b).

[174] However non-annual capacity may also be procured because of market participant buy bids, through adjustments to the reliability requirement, or through the incremental portion of the VRR curve that is included in these auctions.

[175] See PJM (2011d), p. 29.

[176] See PJM (2008f), pp. 39-41.