Monitoring Analytics

Comments of the Independent Market Monitor on PJM's Capacity Performance Proposal and IMM Proposal

The Independent Market Monitor for PJM

September 17, 2014

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Introduction

PJM's Capacity Performance Proposal of August 20, 2014, is an ambitious and timely effort to address some of the significant issues with the current Reliability Pricing Model (RPM) capacity construct. The proposal appropriately focuses substantially on performance issues. The proposal also includes multiple capacity products and much of the detail of the proposal is related to integrating the multiple products with the basic RPM model.

The IMM has identified issues with the RPM model in a series of reports.[1] The issues can be summarized as issues with price formation and issues with performance incentives. These are the two essential components of any capacity market design. One of the key elements missing in the PJM proposal is a mechanism to ensure price formation consistent with the basic market design and the performance incentives.

PJM's goal of modifying the capacity market construct is motivated in significant part by the experience of January 2014 including very high forced outage rates. The IMM agrees that capacity resource performance issues must be addressed and the IMM's proposal would also address the performance issues.

The IMM's proposal is made in response to the PJM proposal and also incorporates substantial elements of the recently approved proposal by ISO-NE to modify the ISO-NE capacity market.[2]

Well functioning capacity markets will ensure customers that reliability is being provided at the lowest possible cost, but no lower. In order to do that, well functioning

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1 The most recent reports are Monitoring Analytics, LLC, "The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses Revised," (August 26, 2014). Monitoring Analytics, LLC, "Analysis of the 2016/2017 RPM Base Residual Auction," (April 18, 2014). Monitoring Analytics, LLC "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013," (September 12, 2013). There is a complete list of capacity market related reports in the *2014 State of the Market Report for PJM: January through June* which can be found at <www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014q2-som-sec5.pdf>.

2 FERC Order Granting Rehearing for Further Consideration, Docket Nos. ER14-1050-002 and EL14-52-001(July 28, 2014).FERC Order 147 FERC ¶ 61,172 (May 30, 2014). ISO New England Inc. and New England Power Pool, Filings of Performance Incentives Market Rules Changes, Docket No. ER14-1050-000 (January 17, 2014). Answer of ISO New England Inc. in Opposition to NEPOOL Alternative Proposal Docket No. ER14-1050-000 and -001 (February 12, 2014). Motion for Leave to Answer Out-of-Time and Answer of ISO New England Inc. Docket No. ER14-1050-000 and -001 (March 3, 2014).

capacity markets will ensure that prices are high enough to incent entry of new units and retention of existing resources, but no higher. In order to do that, well functioning capacity markets will ensure that resources are paid based on their performance consistent with performance in an all energy market, and thus that high performing resources will be rewarded and poorly performing resources will not be rewarded.

The IMM recognizes that the development process for these complex markets is moving very rapidly in PJM and notes that this report excludes some relevant details about the IMM proposal. The IMM will supplement our report and respond to questions as appropriate.

Capacity Market Issues

The IMM has raised issues related to price formation in capacity markets and issues related to performance incentives in capacity markets.

The price formation issues raised by the IMM include the 2.5 percent shift in the demand curve and the nature of demand side participation in the capacity market.

The IMM has recommended that the use of the 2.5 percent demand adjustment in the capacity market be terminated immediately. The 2.5 percent demand reduction is a barrier to entry in the capacity market for both new generation capacity and new Demand Resource (DR) capacity. The logic of reducing demand in a market design that looks three years forward, to permit other resources to clear in Incremental Auctions, is not supportable and has no basis in economics. There are tradeoffs in using a one year forward or a three year forward design, but the design should be implemented on a consistent basis. Removing a portion of demand affects prices at the margin, which is where the critical signal to the market is determined. The IMM has documented the negative impacts of the 2.5 percent adjustment on the price formation process.[3]

The IMM has recommended modifying the treatment of DR in the capacity market. While competition from demand side resources improves the functioning of the market, that is not the result if the demand side resources are not comparable to other capacity resources. The purpose of demand side participation in RPM is to provide a mechanism for end use customers to avoid paying the capacity market clearing price in return for agreeing to not use capacity when it is needed by customers who have paid for capacity. The fact that customers providing Limited DR only have to agree to interrupt ten times per year for a maximum of six hours per interruption represents a flaw in the design of

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3 The most recent examples are: Monitoring Analytics, LLC, "The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses Revised," (August 26, 2014); Monitoring Analytics, LLC, "Analysis of the 2016/2017 RPM Base Residual Auction," (April 18, 2014).

the program. There is no reason to believe that the customers who pay for capacity will need the capacity used by participating load management (LM) customers only ten times per year or a maximum of 60 hours per year or only during defined summer hours. In fact, the probability of needing that capacity will increase with the amount of MW that participating LM customers clear in the RPM Auctions. This limitation means that the demand side resources sold in the RPM Auctions are of less value than generation capacity. As a result, demand side resources can make lower offers than they would if they offered a comparable resource and displace generation resources.[4]

Given the significant impact of demand side resources on the RPM market outcomes, the IMM has recommended that the definition of demand side resources be modified in order to ensure that such resources provide the same value in the capacity market as generation resources in the current RPM design. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources. Such a modification would help ensure that demand side resources contribute to the competitiveness of capacity markets rather than suppressing the price below the competitive level in the current RPM design.

The performance incentive issues in the current capacity market are a result of the weak performance incentives and the inconsistent application of even those weak incentives across types of capacity resources.[5] The performance incentive issues also include the incentives to buy out of capacity positions for demand resources, planned resources and imported resources.[6]

The goal of the capacity market performance incentives should be to match the incentives that would result from a competitive energy only market. The performance incentives in the PJM capacity market fall well short of that objective. The most basic

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4 While PJM has improved its modeling of Limited DR and Extended Summer DR by modifying the way in which the constraints are included in the optimization, PJM has not demonstrated that even this approach is consistent with the price formation mechanism necessary to incent new entry and retain existing resources.

5 Monitoring Analytics, LLC, "IMM White Paper Selected RPM Issues," (August 20, 2012) <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf>

6 Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM re RPM Reform, FERC Docket No. ER14-1461-000, -001 (April 30, 2014) <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_ER14-1461-000-001_20140430.pdf>

market incentive is that sellers should not be paid when they do not provide a product. That is only partly true in the PJM capacity market. There are two areas where the performance incentives are inadequate, overpayment for underperformance and incorrect outage rate definition.[7]

In RPM, a capacity resource will be paid 50 percent of its full capacity market revenues even in the case of complete nonperformance in the first year of such nonperformance. For example, a resource that sold 500 MW of unforced capacity at $150 per MW-day would be paid $75 per MW-day even if the resource did not produce energy when called during any of the PJM-defined approximately 500 RPM critical hours. That decreases to 25 percent in year two of sub 50 percent performance and to zero in year three, but returns to 50 percent after three years of better performance. Under some extreme circumstances, total nonperformance would result in total nonpayment as a result of penalties.

Not all unit types are subject to RPM performance incentives. Wind, solar and hydro generation capacity resources are exempt from key performance incentives. Wind and solar generation capacity resources are not subject to peak hour availability incentives, to summer or winter capability testing or to peak season maintenance compliance rules. Hydro generation and intermittent generation capacity resources are not subject to peak season maintenance compliance rules.[8] Given that all generation is counted on for comparable contributions to system reliability, it would be efficient for all generation types to face the same performance incentives.[9]

In the PJM capacity market, the forced outage rate is a performance incentive. Resource owners sell unforced capacity in the capacity market, which is installed capacity times one minus the forced outage rate for the resource. The higher the forced outage rate, the less capacity can be sold from a generating unit in the capacity market and the lower are the capacity market revenues for that unit. The capacity market should create an incentive to have low forced outage rates in this direct way. The forced outage rate also affects the level of payment actually received for the level of capacity sold in the RPM

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7 See Monitoring Analytics, LLC and PJM Interconnection, LLC, *"Capacity in the PJM Market," (August 20, 2012)*

8 PJM Interconnection, L.L.C., "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012) p. 119. The rationale for this treatment of hydro, wind and solar capacity is unclear.

9 The installed capacity of wind and solar resources is derated when offered in RPM because, even if not on outage, such resources may not be available at times of peak demand. PJM derates wind resources to 13 percent of installed capacity. PJM derates solar resources to 38 percent of installed capacity.

Auctions. The issue in the PJM capacity market is that the forced outage rates used to provide these incentives do not correctly measure actual forced outage performance because they exclude some forced outages and are therefore too low.[10] There is no reason not to reflect all outages in the economic fundamentals of the capacity market and the capacity market outcomes, exactly as they are reflected in PJM system planning. The current incentive design is not consistent with an efficient outcome.

Purpose of Capacity Markets

The fundamental purpose of capacity markets is to address the shortfall in net revenue or the missing money problem that arises from energy markets in the presence of exogenous reliability requirements and incomplete scarcity pricing.

The result of solving the net revenue problem with incentives that are consistent with scarcity pricing is reliability at least cost. The capacity market design must address both price formation and performance incentives issue simultaneously to ensure an efficient and competitive outcome.

An exogenously imposed administrative reliability requirement has generally been interpreted to require the purchase of capacity in excess of expected peak loads by a reserve margin. The reserve margin is designed to ensure reliability under worst case conditions including high demand, forced generation outages and transmission outages. In PJM, the reserve margin requirement has resulted in a level of capacity greater than would have been the result of the operation of an energy only market without such a requirement. The result was lower energy prices for all units and a resultant shortfall of net revenues compared to the annualized costs of building a new generating unit.[11] The introduction of the RPM capacity market was a significant positive step toward resolving this issue. But the PJM capacity market design continues to be imperfect and the resolution of the remaining design issues is critical to the continued success of the PJM market as demand increases and generating units retire.

The reserve margin means that there are units capable of producing energy in excess of demand under most supply and demand conditions. This excess supply means that competition in the energy market results in prices that are set by offers at short run marginal cost based on the cost of fuel, emissions permits and short run variable

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[10] For a more complete discussion of this issue, see the IMM's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, *"Capacity in the PJM Market,"* (August 20, 2012).

[11] See the "*2007 State of the Market Report for PJM*," Volume II, Section 3, Energy Markey, Part 2, Net Revenue.

operation and maintenance expense. The result of these supply and demand conditions is that peaking units, some of which run in a year and some of which do not run, will earn small or zero margins in the energy market. Scarcity pricing in the energy market is one way to address the revenue shortfall issue but scarcity pricing in PJM has not, and is not expected to, result in revenues adequate to solve the problem.

The capacity market design problem has two parts, adequate revenue to incent and sustain investment in generating resources, and incentives for performance consistent with a scarcity pricing regime. The first is the price formation problem and the second is the performance incentive problem.

Definition of Capacity

The RPM capacity market design in PJM was created and defined as a result of revenue sufficiency issues in the energy market. The design of the capacity market reflected this tight integration between energy and capacity markets. The sale of capacity in the capacity market meant that the capacity had to be physical, that the energy from the capacity had to be deliverable to all loads in PJM, that the energy from the capacity had to be offered into the day-ahead energy market and real-time energy market every day, that the energy from the capacity was recallable in an emergency, that capacity resources had to meet minimum performance requirements and that owners of capacity resources had to report outage data.

Physical capacity is needed in order to provide the reliable delivery of energy under all system conditions. In practice that means, for example, that a firm liquidated damages contract is not physical and cannot be capacity. Payment of liquidated damages is not considered an acceptable substitute for the delivery of energy during a period when load approaches the capability of the generating capacity.

Deliverability means that the transmission system must be capable of delivering the energy output from the resource under peak conditions to load anywhere in PJM. Deliverability is enforced by requiring the builder of new capacity to pay for any transmission upgrades necessary to ensure that the energy is deliverable, according to transmission system analysis done by PJM and the transmission owners. This provides a strong incentive to locate where the transmission system is robust and also provides a market signal about the full cost of new capacity when transmission system upgrades are required.

In recognition of the tight integration between PJM energy and capacity markets to ensure reliability and revenue sufficiency, capacity resources are required to offer energy output equal to their full installed capacity value into the day-ahead energy market every day. This requirement reflects the fact that the purpose of the capacity market is to help ensure revenue sufficiency for units operating in PJM's energy markets rather than creating a standalone capacity product.

Energy from all capacity resources that clear in a capacity auction is recallable by PJM in an emergency. This ensures that even when such energy is being exported, PJM customers who paid for the capacity to ensure reliability, have a call on that energy at the PJM market clearing price if the energy is needed to meet load in PJM.

The basic elements of the RPM capacity market design include the definition of capacity as an annual product, a must offer requirement for all capacity resources, a must buy requirement for all load, the recognition that capacity is a physical product, performance incentives and a net revenue offset as the link between energy and capacity markets. The RPM design includes a sloped demand curve with defined inflection points, a three year forward procurement, a locational market definition, and market power mitigation rules.

IMM Capacity Market Design Proposal

Basic Design Elements

The IMM recommends specific market design elements for a modified capacity market. These recommendations are presented in summary form and the IMM recognizes that the details matter and need to be more fully specified.

The capacity market should include a single capacity product with one set of performance incentives. There is no reason to have multiple products. With well designed performance incentives, all sources of capacity can determine how to offer the single capacity product consistent with the physical limits of the resource and the reliability needs of the PJM system. Creating multiple products is the first step towards micromanaging the mix of capacity resources and attempting to substitute the judgment of the planner for market choices.

It may not even be possible to have a well designed capacity market include multiple capacity products because there are indeterminate interactions among multiple products with different reliability characteristics and different performance characteristics, which make it impossible to define IRM using existing software tools. The link between the determination of IRM in PRISM and multiple, contingent products is not well understood and it is not clear that it is currently possible to establish an IRM that is fully consistent with the existence of multiple products with varying reliability characteristics, despite seeming intuitively plausible. It is not currently possible to account for contingent forced outage rates across multiple generating units, let alone multiple product types with additional dimensions. Given this issue, it is difficult or impossible to accurately define the maximum amounts of various products with weaker performance requirements and the pricing mechanism is unlikely to be adequate as a result. As part of this problem, PJM has not demonstrated that the limits it is defining can be expected to result in prices consistent with the contribution of each product type to reliability or product prices consistent with the reliability goal. The IMM has demonstrated the price impacts of the limited demand response products which suppress the price below the level required to support and sustain investment in generation. The fact that demand response products were not required to perform in January further illustrates the significant direct reliability impact of limited products.

The capacity market should no longer include any demand side resources on the supply side of the market, including energy efficiency resources (EE). Demand side resources should be on the demand side of the market where they can and should be a very significant component of the capacity market. PJM needs to take clearly defined steps to facilitate such demand side participation. Load that does not want to pay for capacity and is willing to interrupt its use of capacity when that capacity is needed by those who do pay for it, should be able to avoid paying for capacity. That is the demand side of the market as it should work and can work.

The capacity market should include an explicit price formation mechanism designed to result in prices equal to the amount of the net revenue shortfall. This is net CONE (cost of new entry). Net CONE is the gross annual cost of new entry for a peaking unit net of expected revenues from the energy, ancillary services and other markets, including uplift payments. To the extent that net CONE is positive, the other PJM markets are not providing enough revenue to induce entry or to sustain existing investments and net CONE must be consistently recovered in the capacity market.

The PJM capacity market has fallen short of that goal. Table 1 shows the net CONE, clearing price, and cleared MW for rest of RTO and the LDA with the highest clearing price, for each Base Residual Auction held since RPM was implemented for the 2007/2008 Delivery Year. At the RTO level, clearing prices have been less than net CONE in every year of RPM except one. The average ratio of annual clearing prices to net CONE for rest of RTO was 41.7 percent. In the LDAs with the highest clearing price in each delivery year, the clearing prices have equaled or exceeded the LDA net CONE for six of the 11 BRAs. The average ratio of annual clearing prices to net CONE for the highest price LDA in each year was 103.6 percent. However, the average quantity of capacity cleared in the highest price LDA when the LDA cleared separately was only 8,307 MW. In other words, most capacity has been paid substantially less than net CONE under RPM.

Table 1 Net CONE, clearing price, and cleared MW for RPM Auctions from 2007/2008 to 2017/2018[12]

	RTO				Highest LDA Clearing Price			
Delivery Year	Net CONE ($ per MW-day)	Annual Clearing Price ($ per MW-day)	Annual Clearing Price to Net CONE	Cleared MW	Net CONE ($ per MW-day)	Annual Clearing Price ($ per MW-day)	Annual Clearing Price to Net CONE	Cleared MW
2007/2008	$171.87	$40.80	23.74%	88,410.2	$148.47	$197.67	133.14%	30,797.8
2008/2009	$172.25	$111.92	64.98%	88,745.1	$159.02	$210.11	132.13%	10,621.2
2009/2010	$172.27	$102.04	59.23%	59,684.1	$159.04	$237.33	149.23%	9,914.6
2010/2011	$174.29	$174.29	100.00%	130,670.7	$131.87	$186.12	141.14%	1,519.7
2011/2012	$171.40	$110.00	64.18%	132,264.5	$171.40	$110.00	64.18%	132,264.5
2012/2013	$276.09	$16.46	5.96%	70,691.1	$212.50	$222.30	104.61%	1,354.1
2013/2014	$317.95	$27.73	8.72%	85,103.4	$227.20	$247.14	108.78%	4,791.7
2014/2015	$342.23	$125.99	36.81%	76,189.3	$275.02	$225.00	81.81%	3,379.7
2015/2016	$320.63	$136.00	42.42%	81,710.0	$358.22	$357.00	99.66%	9,228.0
2016/2017	$330.53	$59.37	17.96%	88,742.7	$329.94	$219.00	66.38%	5,686.4
2017/2018	$351.39	$120.00	34.15%	151,804.9	$365.87	$215.00	58.76%	5,778.4

The IMM proposes that offers in the capacity market be capped at net CONE, adjusted for the ratio of total demand to total capacity purchased.[13] There is no need for an additional risk premium as relevant risk is captured in the rate of return included in the net CONE calculation.[14]

The IMM recognizes that this would be a substantial departure from the current price formation process but it is a change that is required if the capacity market is to function as intended. IMM analysis has shown that prices which would result from an RPM construct with its major flaws corrected are close to net CONE.[15] Competition could reduce actual clearing prices to levels below net CONE or above net CONE but the expected equilibrium price is net CONE. The demand or Variable Resource Requirement (VRR) curve is unaffected by this recommendation.

The capacity market should include clear performance incentives consistent with those that exist in an all energy market. In summary, the appropriate performance incentives increase payments when resources provide energy during high demand periods and

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12 Net CONE values are on a UCAP basis.

13 Additional details are required to make this concept precise and operational including the need to address unit performance and the option for existing resources to increase offers above net CONE if net ACR is greater than performance revenues. The additional details will be provided.

14 This proposal is about unit offers only and does not affect the price formation process based on the supply curve and the defined demand or VRR curve.

15 BRA sensitivities report Monitoring Analytics, LLC, "The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses Revised," (August 26, 2014).

reduce payments when resources do not provide energy during high demand periods. The IMM recommends a two settlement approach like that proposed by ISO-NE which is based on MW deviations from required performance measured as a share of the total requirement for capacity in an hour.

Consistent with that design objective, there are no excuses for lack of performance. Failure to perform means paying back a proportionate share of capacity market revenues with the potential of paying back more than the revenues in the case of poor performance subject to an appropriate cap on negative payments.[16] The inadequacy of attempting to control unit performance through micromanaging unit parameters and characteristics has been demonstrated. In January 2014, when the PJM territory faced extreme cold weather conditions and had record winter peak loads, the forced outage rate was extremely high. Capacity resources were not available when most needed. The inadequacy of attempting to require capacity resources to be physical assets through affidavits and other requirements has also been demonstrated.

The performance incentives should be linked directly to net CONE spread over the high load hours. For example, with a net CONE of $351.78 per MW-day, or $128,400 per MW-year and 600 high load hours per year, without any additional adjustment, the hourly performance rate would be $214.00 per MWh.[17] If a unit provided more than its proportional share of energy in the high load hour, it would receive this payment and if a unit provided less than its proportional share of energy in the high load hour it would make this payment. The performance requirement is a function both of total required generation and the unit's share of the total requirement for capacity on the system.[18] Again following the FERC approved ISO-NE design, the IMM recommends that these payments be made by generators with below required performance to generators with above required performance.

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[16] The IMM also proposes a limit on net negative payments by capacity resources comparable to the ISO-NE stop loss provisions.

[17] The 600 hours is an estimate of the hours referenced by PJM as high load. The ISO-NE uses 21.2 scarcity hours in comparable calculations. The appropriate value is likely between these two numbers. The IMM will do additional analysis with the goal of defining the determinants of the appropriate value. There is a potential inconsistency between energy market and capacity market incentives when energy market prices are relatively low and capacity market incentive payments are relatively high, which can happen during some of the 600 hours based on historical data.

[18] This is an overview and the details can be provided. The design of the incentives follows FERC Order 147 FERC ¶ 61,172 (May 30, 2014).

Market power continues to be endemic to the PJM capacity market as a result of the ownership structure of capacity resources. While moving towards an offer cap of net CONE eliminates some elements of market power review or reduces their significance, it creates others. The must offer requirement should be retained because the capacity market cannot function without a must offer requirement. ACR will continue to require review as will the various components of capacity market offers. Equal and open access to interconnection queues and elimination of queue bottlenecks becomes a more urgent issue.[19]

IMM Proposal Differences from PJM Proposal

While the IMM proposal shares the fundamental goals of the PJM proposal there are some key differences.

The IMM proposal includes a single capacity market product while the PJM proposal includes multiple capacity products.

The PJM proposal includes four broad capacity products with sub classes of assets within these products.[20] The PJM proposal imposes maximum quantities to procure in the RPM auction clearing process for base capacity, extended summer and limited demand response products.

The IMM proposal includes a mechanism to ensure that market prices reflect the net revenue shortfall or missing money which is to set the offer cap at net CONE.

The PJM proposal does not include such a mechanism.

The IMM proposal includes performance incentives which are solely a function of the provision of energy and reserves during high load hours and which apply equally to all capacity resources. The IMM proposal links performance payments to a predetermined value based on net CONE and which therefore vary solely with deviations in the quantity of energy and reserves provided on high load days compared to the committed quantity.

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19 See the *2014 State of the Market Report for PJM: January through June*, Section 12 – Generation and Transmission Planning <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014q2-som-pjm-sec12.pdf> (August 14, 2014).

20 For example, within the performance capacity product, PJM defines three subclasses of generation assets, base load, interday cycling and intraday cycling; and four subclasses of other resources, energy efficiency, demand response, storage technologies and external capacity, each with its own availability and flexibility requirements.

The PJM proposal imposes high and difficult to predict risks on generators as a result of including both quantity and price (LMP) risk in the performance incentives.

The IMM proposal does not provide for exceptions to the performance incentives. All units are subject to the same performance payment regardless of the reason for underperformance.

PJM's proposal includes exemptions for units that are not committed by PJM or dispatched down by PJM for providing ancillary services or because of transmission constraints. A unit's commitment and dispatch is inherently a function of its parameters and economics. These exemptions allow inflexible and noneconomic units to stay in the market instead of retiring. They do not contribute to reliability in the same way as other units and exempting them from penalties sends the incorrect signal that they are preferred in place of more efficient and flexible resources.

The IMM proposal includes a must offer requirement for all capacity resources, which includes the ability of unit owners to incorporate the costs of being a capacity resource in such offers.

The PJM proposal does not appear to include an explicit must offer requirement. The IMM recommends, within the PJM proposal framework, that there be a must offer requirement for all capacity resources that includes coupled base and performance offers and that includes the ability of unit owners to incorporate the costs of being a capacity resource in such offers.

Transition: 2018/2019 Delivery Year

The complexities of what PJM proposes, or what the IMM proposes, as a complete solution, make full implementation for the 2018/2019 delivery year impossible to complete with the requisite attention to all relevant details. The markets are complicated and need to be redesigned with attention to all the details.

The IMM suggests interim steps towards PJM's goals for the 2018/2019 BRA with further development of the details prior to more complete implementation for the 2019/2020 delivery year.

These interim steps should include steps addressed to price formation and steps addressed to performance incentives. The interim steps related to price formation should include: elimination of the 2.5 percent shift of the demand curve; elimination of the limited demand response product; elimination of the summer unlimited demand response product; potential substitution of a true demand side product for the annual demand response product; and inclusion of all required and appropriate fuel related costs in ACR and APIR. The interim steps related to performance incentives should include: eliminating all OMC outages; eliminating all lack of fuel outages for calculating performance; putting 100 percent of capacity market revenues at risk; and applying the same performance incentives to all resources.

These interim steps can be implemented without significant uncertainty within the existing RPM framework and with the knowledge that these steps would represent substantial progress in the direction identified by PJM towards a sustainable market.

Transition: 2015/2016 Delivery Year

PJM has indicated a need to acquire additional resources and to enhance performance requirements for the 2015/2016 delivery year, although the BRA for that year has been run and prices established.

The IMM recommends that performance requirements be immediately enhanced by: eliminating all OMC outages; eliminating all lack of fuel outages for calculating performance; putting 100 percent of capacity market revenues at risk; and applying the same performance incentives to all resources. There is no reason not to make all these changes immediately. These are minimum requirements for capacity resources to meet performance obligations and should have been implemented in prior years.

The IMM recognizes that additional steps may be needed for the 2015/2016 delivery year in order to ensure reliability and is continuing to consider how to best define such steps.

Sensitivity Analyses

In order to help understand some of the implications of the PJM proposals, the IMM has run a set of sensitivity analyses using the offers from the 2017/2018 BRA.[21] Table 2 shows the sell offer and parameter changes used for each of the sensitivity scenarios. Table 3 presents a qualitative description of the RTO Base Capacity price in the sensitivity scenario compared to the Annual price in the actual BRA, the RTO Capacity Performance price in the sensitivity scenario compared to the Annual price in the actual BRA, and the price separation between the Base Capacity and Capacity Performance prices in each of the sensitivity scenarios.

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21 Monitoring Analytics, LLC. Memo to the Capacity Performance Enhanced Liaison Committee re Capacity Performance Product Assumptions (September 15, 2014) <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_ELC_Capacity_Performance_Product_Assumptions_20140915.pdf>

Table 2 Sensitivity scenario assumptions

Scenario	Cap on Non-Performance Products	Risk Premium for Capacity Performance Resources ($ per MW-Day)	Fuel Reliability for Unclassified Gas Resources	Firm Transportation Cost ($ per MW-Day)	Dual Fuel Cost ($ per MW-Day)	Offer Strategy for Unclassified Gas Resources	STRPT Reduction for VRR	STRPT Reduction for Sub-Annual Resource Constraint	STRPT Reduction for Limited Resource Constraint	Generation and Annual DR Only
1	15%	$10.00	Firm transportation	$180.00	NA	Coupling	No	Yes	Yes	No
2	15%	$10.00	Dual fuel capability	NA	CT = $143.28 * CRF CC = $153.23 * CRF	Coupling	No	Yes	Yes	No
3	15%	$10.00	Firm transportation	$180.00	NA	Coupling	No	NA	NA	Yes
4	15%	$10.00	Dual fuel capability	NA	CT = $143.28 * CRF CC = $153.23 * CRF	Coupling	No	NA	NA	Yes
5	15%	$25.00	Firm transportation	$180.00	NA	Coupling	No	NA	NA	Yes
6	15%	$25.00	Dual fuel capability	NA	CT = $143.28 * CRF CC = $153.23 * CRF	Coupling	No	NA	NA	Yes
7	25%	$25.00	Firm transportation	$180.00	NA	Coupling	No	NA	NA	Yes
8	25%	$25.00	Dual fuel capability	NA	CT = $143.28 * CRF CC = $153.23 * CRF	Coupling	No	NA	NA	Yes
9	50%	$10.00	NA	NA	NA	No coupling	No	NA	NA	Yes

Table 3 Sensitivity scenario results

Scenario	RTO Base Capacity Price Compared to Annual Price (in Actual BRA)	RTO Capacity Performance Price Compared to Annual Price (in Actual BRA)	RTO Base Capacity and Capacity Performance Price Separation
1	Significant decrease	Significant increase	Significant
2	Significant increase	Significant increase	Significant
3	Significant increase	Significant increase	None
4	Significant increase	Significant increase	Small
5	Significant increase	Significant increase	Small
6	Significant increase	Significant increase	Small
7	Significant increase	Significant increase	Small
8	Significant increase	Significant increase	None
9	Significant increase	Significant increase	None

There are some preliminary conclusions that can be drawn from these sensitivities. Coupling offers for resources that cannot currently meet the requirement to be Capacity Performance tends to decrease the price separation between Base Capacity and Capacity Performance prices. Reducing the maximum amount of Base Capacity resources tends to increase the Capacity Performance price and the price separation between Base Capacity and Capacity Performance products. The requirement to use firm gas transportation has a larger impact on clearing prices than would the requirement to install dual fuel capability.