This document contains MA's comments on PJM's scarcity pricing whitepaper. The posting of this document was delayed while we discussed some of these comments with PJM. We appreciate PJM's effort to summarize their current thinking on this matter and to engage in a continued dialogue on this complex subject. We believe that providing our detailed comments will provide a way to keep this discussion moving forward.

UPDATED: PJM Proposal for Price Formation during Operating Reserve Shortages

October 15, 2009 SPWG

Purpose and Summary of Proposed Mechanism

The purpose of this document is to fully explain the operating reserve shortage pricing (aka scarcity pricing) mechanism that PJM first proposed in PJM Task Force 719 in general, and the details of which the Scarcity Pricing Working Group (SPWG) has been developing since April 2009. This mechanism is intended to not only comply with the criteria set forth by the FERC in Order 719, but also provide greater system control and more rational, consistent pricing when the RTO, or regions of it, are in or near an operating reserve shortage.

PJM's proposal is to implement an operating reserve demand curve (ORDC), also known as a reserve constraint penalty factor curve (RCPFC), as the pricing mechanism (aka scarcity pricing mechanism) to be used during periods of operating reserve shortage. This methodology has been previously approved by FERC and employed in the Midwest ISO, New York ISO and the New England ISO. PJM's rationale for proposing an ORDC/RCPFC framework is to ensure smoother, more rational price transitions from nonshortage conditions to reserve shortage conditions than exist under the current scarcity pricing mechanism, provide greater transparency and operational visibility to market participants regarding the transition to reserve shortage conditions, and most importantly enhance operational reliability during shortage conditions.

In addition to the ORDC/RRCPFC, PJM proposes that market power mitigation screening in the form of the Three Pivotal Supplier Test (TPST) and mitigation of suppliers found to fail the TPST to cost-based offers remain in place during periods of operating reserve shortage to ensure that price formation during reserve shortages are a function of the underlying supply-demand balance and not as a result of potential exercise of market power.

Implementation of an ORDC/RCPFC requires the joint and simultaneous optimization and pricing of reserves and energy on a 5-minute basis to ensure that system needs are met in the most efficient manner on a 5-minute basis, which is a change from how reserves and energy are optimized today. The implementation of the ORDC/RCPFC with joint, simultaneous optimization of energy and reserves provides price signals for energy and reserves that factor in the opportunity costs of providing capacity in one market, when it may have been profitable to provide that same capacity to another market. Moreover, the use of an ORDC/RCPFC with joint, simultaneous co-optimization and reserves in the dispatch algorithm also preserves the use of LMP and locational price signals with the region in which the operating reserve shortage pertains thereby avoiding the need to manually dispatch generation to alleviate local constraints.

Comment [A1]: Optimizing energy subject to constraints

Additionally, PJM proposes to explicitly define a 10-minute non-synchronous reserve product market so that an explicit price can be attached to meeting PJM's Primary Reserve requirement during non-shortage conditions and the price paid for being short of the Primary Reserve requirement.

There remain implementation details regarding the new mechanism for pricing during an operating reserve shortage as it relates to emergency procedures. To the extent possible, emergency procedures and the new reserve shortage pricing mechanism should be harmonized and not work against each other.
The goal of harmonizing emergency procedures and the new pricing mechanism should be to enhance PJM operational control of the system during periods of reserve shortage as well as send price signals that are aligned with system conditions. For example, the invocation of emergency procedures should not result in prices that decrease, but should at minimum keep prices at the same level as prior to the emergency condition or increase prices as a signal the system has entered emergency procedures. However, the prices resulting from emergency procedures should not make it more difficult to manage the system and should not require the manual dispatch of resources if possible.

The remainder of the proposal is organized as follows. First, a short background regarding FERC Order 719 and pricing during operating reserve shortages and the current PJM scarcity pricing mechanism is provided, followed by discussion defining an ORDC/RCPFC, how and ORDC/RCPFC helps transition prices into reserve shortage conditions, and the need for joint, simultaneous optimization of energy and reserves to implement the ORDC/RCPFC construct. Next, implementation details regarding reserve requirements, reserve regions and markets, and the shape of the ORDCs/RCPFCs for each reserve product is outlined. Finally, a discussion of remaining implementation issues harmonizing the ORDC/RCPGC paradigm with emergency procedures so as to enhance operation control and ensure prices are commensurate with system conditions.

Background: FERC Order 719

FERC in Order 719 states that either current mechanisms or proposed mechanisms for price formation during an operating reserve shortage (aka scarcity) "ensure that the market price for energy accurately reflects the value of such energy during shortage periods (i.e., an operating reserve shortage).[1] Moreover, any mechanism for price formation during an operating reserve shortage should achieve the goals of Order 719 of "maintaining reliability, eliminating barriers to the comparable treatment of demand response, and allocating energy during a shortage to those who value it most."[2] Order 719 goes on to require the RTO to describe how its pricing mechanism during an operating reserve shortage satisfies the six criteria enumerated by the Commission:[3]

- Improve reliability by reducing demand and increasing generation during periods of operating reserve shortage;
- Make it more worthwhile for customers to invest in demand response technologies;
- Encourage existing generation and demand resources to continue to be relied upon during an operating reserve shortage;
- Encourage entry of new generation and demand resources;

[1] See Order 719, paragraph 166.
[2] See Order 719, paragraph 235.
[3] See Order 719, paragraph 247.

• Ensure that the principle of comparability in treatment of and compensation to all resources is not discarded during periods of operating reserve shortage; and

• Ensure market power is mitigated and gaming behavior is deterred during periods of operating reserve shortages including, but not limited to, showing how demand resources discipline bidding behavior to competitive levels.

The above six criteria provided by the Commission in Order 719 have influenced the decision to propose an (ORDC/RCPFC) as the pricing mechanism to be used during an operating reserve shortage (aka scarcity pricing mechanism).

Background: Current Scarcity Pricing Mechanism

As stated in both Task Force 719 and the SPWG, PJM's current scarcity pricing mechanism is not consistent with pricing during operating reserve shortages nor is it completely compliant with the criteria delineated in Order 719. The existing scarcity pricing mechanism does not result in price impacts explicitly tied to operating reserve shortages, but only to the implementation of emergency procedures. The existing mechanism also - does not ensure market power is mitigated because all market power mitigation within a scarcity pricing region is lifted when a scarcity event is triggered. Furthermore, the current scarcity pricing mechanism can result in volatile prices that do not provide enough forward notification to allow all capable resources to respond to reserve shortage conditions, and can at times lead to prices that are not indicative of system conditions. One example of this is that when a scarcity constraint is enabled triggering scarcity pricing, the prices in each scarcity pricing region are set to the bid of the highest generator bid price operating at PJM's direction, plus losses. This results in high prices in a scarcity pricing region which incents generators and demand response to participate but does not allow for the dispatching of local constraints within the scarcity pricing regions that potentially pose reliability concerns. Rather than explicitly control for local constraints through the dispatch algorithm, PJM operators must manually dispatch generators for such local constraints resulting in reducing generator outputs when the price for that generator is high due to the scarcity condition.

The pricing of energy and reserves during the scarcity event of August 8, 2007provides another example related to prices and system operation. The cost of synchronized reserves, in the form of lost opportunity costs, exceeded $900/MW for some units committed to provide reserves even though the market-clearing prices for synchronized reserves that were calculated for those hours were at or near $0/MW. Rather than explicitly pricing reserves simultaneously in the dispatch algorithm, PJM operators needed to manually dispatch resources downward to maintain some level of reserves because the price of energy appeared more attractive to generators than reserves. The effective reserve price during August 8, 2007 was not transparent to market participants and prices were not consistent with operational needs. This displays both the need for a more cohesive set of energy and reserve prices that will be calculated via the proposed joint optimization and also gives a realistic price of reserves during shortage conditions.

Comment [A2]: The described difference between the synchronized reserve clearing price and the opportunity costs was a result of a problem with the constraints used to define the MidAtlantic synchronized reserve market and the failure to forecast high LMPs when running the hour ahead synchronized reserve market. Prior to March 15th 2009, 70% of Tier 1 west of Bed Bla was considered deliverable. Since March 15th, 15% of Tier 1 west of AP South is considered deliverable.

Comment [A3]: Neither is correct. All participants knew that they would made whole to real time energy market prices and the amount of synchronized reserves called on was consistent with operational needs.

ORDC/RCPFC Defined

An ORDC/RCPFC defines a relationship between the quantity the RTO or sub-region of the RTO goes short of a particular reserve product (actual real-time reserve quantities are less than required or target reserve levels) and the price of reserves at various levels of reserve shortage. Implicitly an ORDC/RCPFC defines the system's willingness to pay to maintain a specific reserve product, in a single area and ignoring product substitution, at the required or target level before allowing the specific reserve product to go into shortage. Equivalently, an ORDC/RCPFC reflects the value of various levels of reliability that different levels of reserves provide to consumers of reliability which includes both the supply and demand-side of the market.

As a simple example of an ORDC/RCPFC, suppose it is decided that market participants are not willing to pay more than $800/MW in order to maintain a generic reserve target of 1200 MW. Equivalently stated, the penalty factor for being unable to maintain the 1200 MW target is $800/MW. The price of reserves can be anything between $0/MW and $800/MW as long as the reserve target is met. Once the reserve target can no longer be met, the price of reserves becomes $800/MW Setting the reserve price cap too low may cause a divergence between actual dispatch practice and dispatch software solution.

It is critical to reiterate that the penalty factors themselves not only impact the way energy and reserve prices transition but also directly impact the amount of reserves that will be committed..

How an ORDC/RCPFC and Joint Optimization Methodology Affect the Energy Price and Reserve Prices during an Operating Reserve Shortage

Under normal operating conditions when there is no reserve shortage, the ORDC/RCPFC itself does not explicitly impact the energy price. In these circumstances, the penalty factor price does not at all impact system LMPs or reserve prices because the system's reserve needs can be met at a cost lower than the penalty factor which indicates that there is no reserve shortage. The penalty factor, as defined here, merely sets a cap on the willingness to pay for reserves (max opportunity cost).The only instance when the ORDC/RCPFC will directly impact LMPs and reserve prices is when there is an actual reserve shortage on the system.

The reserve price and quantity relationship determines the reserve price based upon market supply conditions and feeds back into the energy price in the form of an opportunity cost, thereby raising energy prices commensurate with tightening system conditions. This feedback is a direct result of the product substitution between energy and reserves that is explicitly accounted for in the joint, simultaneous cooptimization of energy and reserve that is a key operational feature of an ORDC/RCPFC embedded explicitly within the security constrained economic dispatch (SCED) algorithm. Moreover, the reserve price quantity relationship effectively creates price responsiveness in the demand for energy at higher prices when the supply-demand balance for energy and reserves is becoming tighter by allowing reserves to go into shortage in order to maintain energy balance.

For example, consider a generator with a marginal cost of $200/MWh with a capacity of 400 MW operating in a combined energy and reserve market where the penalty factor for going short reserves is $300/MW. The generator is capable of providing up to 200 MW of its capacity as reserves. Suppose this generator is marginal in that it is the highest cost generator operating at PJM's direction on the system, but is only dispatched for 300 MW of energy leaving 100 MW to be supplied for reserves, but the system is short reserves so the reserve price is $300/MW. If the energy market price is set at the cost of the marginal generator, $200/MWh, the generator has no incentive to provide energy up to 300 MW since the reserve price is $300 for which the unit would not have to expend any costs. It would rather supply the maximum amount of reserves possible (200 MW) at no cost, and receive revenue of $300/MW and only be dispatched for 200 MW of energy for which it breaks even. That is, there is a $300/MW opportunity cost

Comment [A4]: It is not value of reliability. There can be a shortage of reserves, which indicates a reduction in reliability, but not the elimination of reliability. It therefore does not reflect, nor is it expected to reflect, the full "value" of reliability.

Comment [A5]: This suggests that there are available resources with higher prices. This cannot be correct with an offer cap of $1,000.

Comment [A6]: Optimization presumes economic rationale in the decision making process used to allocate limited resources. Where the price of reserves exceeds the max price willing to pay for reserves ($800), the optimization is showing that an additional MW of energy is more valuable than an a additional MW of reserves. It may be true that additional reserves are physically available, but the "decision maker" is choosing energy at this point, and the use of emergency measures, as the least cost solution to the optimization problem.

Comment [A7]: The matchup between operation decisions and the dispatch optimization should be driving the determination of the maximum price to be paid for reserves.

Comment [A8]: See comment and text above.

Comment [A9]: The maximum price that the market is willing to pay for reserves need not be the direct impact on LMP during an actual reserve shortage. .

Comment [A10]: The penalty factor is the max price that the market is willing to pay for reserves, and thereby set the maximum opportunity cost that the market is willing to pay to reserves for foregone energy production.

Comment [A11]: There is nothing inherent in the algorithm that requires a $1 for $1 relationship between the max opportunity cost paid to reserves for foregone energy production and the LMP adder put on the LMP at the marginal units bus(es). If for example, the "feedback" mechanism set the LMP at the marginal bus(es) at $1000, a max opportunity cost of $1000 made available to reserves, would be internally consistent with all dispatch decisions and the substitutability between reserves and energy. Since the LMP would be set at $1000, the price of reserves (the max opportunity cost) would not exceed $1000.

Comment [A12]: The current market paradigm limits "dispatchable" resources at $1000. Prices can exceed this based on DFAX and constraints, but the max price of resources is $1000. There has not been evidence that the $1000 cap on "recognized" resources in the energy market, particularly in the context of the RPM market, has prevented the reliable operation of the system within it designed parameters (1 in 10 years).

Comment [A13]: This example presumes that the $200 unit is the LAST unit available for energy.

(the reserve price) for supplying energy up to 300 MW. Consequently, the opportunity cost of forgone reserve profits must be reflected in the energy price. The resulting energy price would therefore be $500/MWh reflecting the marginal cost of the highest cost generator ($200/MWh) plus the opportunity cost of not providing reserves when it is profitable to do so ($300/MWh). The market price for energy is in part being set by the ORDC/RCPFC in combination with the supply and demand conditions in the market. Prices rise without the need for the generator to submit an energy supply offer price that is different from its marginal cost of providing energy.
Counter example, using MA's $1000 Scarcity Event/$1000 Max Opportunity Cost Proposal:

For example, consider a generator with a marginal cost of $200/MWh with a capacity of 400 MW operating in a combined energy and reserve market where the max opportunity cost for reserves is $1000/MW, and in the event that the market goes short reserves, the price at the marginal unit bus is set to $1000/MW. The generator is capable of providing up to 200 MW of its capacity as reserves. Suppose this generator is marginal in that it is the highest cost generator operating at PJM's direction on the system. The unit has been dispatched to provide 300 MW of energy and 100 MW of reserves. Assume the system needs 101 MW of reserves and this unit is the last available resource. The system is short reserves by 1 MW, so the energy price is set to $1000 at the marginal unit reference bus (this unit's bus). The opportunity cost for providing reserves from this unit is then $1000 - $200 = $800. Since this is the marginal unit for energy and reserves, it set the price at reserves at $800. The unit is indifferent between providing 300 MW of energy at $1000 and providing 100 MW of reserves at $800. So long as the reserve market accurately reflect the opportunity cost of forgone energy profits, the unit will follow dispatch. The energy price is set to reflect that the system has run out of reserves ($800 over the marginal cost of the marginal unit, which the $/MW needed to get the price to $1000) and the reserve market reflects the marginal opportunity cost of $800. This parallels PJM example in that, $1000/MWh reflects the marginal cost of the highest cost generator ($200/MWh) plus the opportunity cost of not providing reserves when it is profitable to do so ($800/MWh). Prices rise without the need for the generator to submit an energy supply offer price that is different from its marginal cost of providing energy.

In the alternative, suppose the above generator is marginal and is dispatched to 300 MW for energy with 100 MW allocated to reserve, but that there is so much supply of reserves the price of reserves is $0/MW. In this case the ORDC/RCPFC has no effect on the energy price which would be the cost of the marginal unit, $200/MWh.

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Joint and Simultaneous Optimization of Energy and Reserves Provide More Efficient Dispatch and Better Operational Control at All Times

The joint and simultaneous optimization of energy and ancillary services necessary to implement an ORDC/RCPFC provides the ability better capture the costs and substitution of these products each time the system is re-optimized to meet reserve targets or to control changing transmission constraints. The proposal envisions the joint and simultaneous optimization of energy, synchronized reserves and primary reserves. Jointly optimizing these products will provide the following benefits:

• *The ability to accurately track Tier 1 reserves throughout each operating hour and commit Tier 2 based on real-time data as opposed to an hour ahead forecast.*

Currently PJM's synchronized reserve market commits Tier 2 reserve based on an hour-ahead forecast that may or may not accurately reflect the operating conditions during the actual hour. The ability to recalculate and track Tier 1 reserves in real-time as well as commit Tier 2 only when needed will ensure that the required reserves are kept on the system at all times and at the lowest cost.

• *Five minute integrated prices for reserves, energy and regulation.*

The new five minute ancillary service prices will fully capture the cost of ancillary services in each five minute interval such that it would virtually eliminate the need for after-the-fact opportunity cost payments because the five minute clearing prices would accurately capture those costs in real-time. After-the-fact opportunity cost payments are made on a resource-specific basis which limits some potential revenue streams for generation and demand resources participating in these markets. The current method of optimizing the real-time dispatch and ancillary services independently can, and has, resulted in divergences in energy and ancillary services prices when the system is stressed. During the August 8th, 2007 scarcity event PJM energy prices crested at $1,000/MWh while the average regulation clearing price was $137 for the same period. Similarly, the Mid-Atlantic Sub-Zone, the region most comparable to where scarcity was declared, cleared little or no synchronized reserves beyond Tier 1 reserves and yielded a $0/MWh clearing price for all but one hour where it was $6/MWh.

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2007	8	7	0	0.1	135	8	0.1	0.1	14.3001	143.001	0.1
2007	8	7	7	18.68	0	189	18.68	18.68	6923.92536	189.602	36.52
2007	8	7	9	15.67	0	272	15.67	15.67	4603.32264	271.392	16.96
2007	8	7	10	10	0	286	10	10	4980.22	286.603	17.38
2007	8	7	11	7.5	0	107	7.5	7.5	2000.48	106.888	18.72
2007	8	7	14	7.5	0	62	7.5	7.5	3285.17	61.708	53.24
2007	8	7	15	7.5	0	150	7.5	7.5	6357.5475	149.709	42.47
2007	8	7	16	7.5	0	20	7.5	7.5	250.21	20.704	12.09
2007	8	7	17	6	0	70	6	6	419.388	69.898	6
2007	8	8	0	$ 29.37	0	171	29.37	29.37	$ 5,176.73	171.005	30.27
2007	8	8	1	$ 7.71	0	145	7.71	7.71	$ 3,537.58	144.997	24.4
2007	8	8	7	$ 8.03	90	44	8.03	8.03	$ 1,072.85	133.605	8.03
2007	8	8	17	**$ 6.00**	0	82	6	6	**$ 32,326.48**	81.691	**395.72**
2007	8	8	18	$ 6.00	0	82	6	6	$ 740.29	81.698	9.06
2007	8	9	8	6	0	67	6	6	399.6	66.6	6
2007	8	9	10	48.87	0	262	48.87	48.87	12784.44087	261.601	48.87
2007	8	9	11	7.5	0	14	7.5	7.5	102.69	13.692	7.5
2007	8	9	13	7.5	90	73	7.5	7.5	2092.79	162.716	12.86

Comment [A14]: This can be set up in a number of ways (nested minimum requirements for the components of 10 minute reserves).

Comment [A15]: This proposal does not affect the ability to track Tier 1 resources.

Comment [A16]: This ability is not in evidence. One of the threshold issues for the implementation of the mechanism, whether it be on an hourly or 5 minute dispatch, is going to be the ability to accurately measure the amount of Tier 1 and Tier 2 reserves available.

Comment [A17]: There is no evidence that attempting to run the synchronized reserve market more than hourly will have any impact on the level of Tier 2 commitments.

Comment [A18]: Where did this come from?

Comment [A19]: This does not change how these costs are collected or the total amount of money that would be collected (barring changes in dispatch based on a different solution). If you go into the hour with a price of $6 for reserves, based on the expected opportunity costs, and the expectation is met, this money is collected through after the fact opportunity cost payment in the form of uplift. If the expectation is wrong, and LMP is higher than expected, the price of reserves is "trued up" to reflect the change in actual opportunity cost, and is collected through after the fact opportunity cost payments on a load weighted ratio share in the form of uplift.

Comment [A20]: While that can be true going into the hour, the market is trued up based on actual opportunity cost in the hour. So, when the price goes to $1000, the opportunity cost paid to units is updated accordingly in terms of actual payment.

Comment [A21]: The hour ahead price does not reflect the full payment for these services. Each of these products requires the payment of opportunity cost based on foregone (if any) locational energy revenues as well.

Comment [A22]: The regulation market cleared on expected price and opportunity cost. Payment to the unit will be adjusted based on actual system conditions in the hour.

Comment [A23]: In order for the market to clear with no Tier 2 indicates that software thought it had more than enough Tier 1 going into the hour to meet its sync requirements. Under these circumstance, the hour ahead Tier 2 should clear at zero, as there would be no demand for Tier 2 ... [1]

Comment [A24]: This does not mean that the resources were only paid $6. There was a true up based on actual within hour opportunity cost. See Table. 81 MW of Reserve was bought in the ... [2]

Comment [A25]: In part this result was due to misspecification of the Sync Market. The role of constraints limiting the deliverability of reser ... [3]

• *Better system control by considering the impacts of ancillary services in each dispatch iteration.*

As stated above, the current ancillary service markets are not optimized through the real-time dispatch algorithm but are cleared using the best forecast information available at the time. This can lead to the commitment of resources for reserves that would otherwise potentially be more economic providing energy or controlling a transmission constraint. Jointly optimizing energy and ancillary services will provide better energy and ancillary services commitments that will not need to be manually altered by PJM dispatchers intra-hour.

• *Smoother price transitions in and out of potential or actual reserve shortage situations.*
The key component in transitioning prices gradually is jointly optimizing the products being provided, in this case, energy and reserves. Ensuring that the least cost balance of these resources is met every 5-minutes and articulated through a cohesive set of 5-minute prices for all products will make certain that product substitution is accurately captured and changing system conditions are met optimally and priced immediately.

Comment [A26]: 5-minute dispatch has nothing necessary to do with scarcity pricing. One step at a time.

Comment [A27]: This needs more development.

An ORDC/RCPFC and Joint Optimization Provide Gradual, Predictable and Transparent Price Changes

A common misconception about the use of an ORDC/RCPFC is that once the system goes into an operating reserve shortage, energy and reserve prices will instantaneously jump significantly like we see today when scarcity is triggered with the declaration of defined emergency procedures. This smoother price transition is aided by keeping market power mitigation in place during reserve shortages as well as the joint and simultaneous optimization of energy and reserves. The energy prices prevailing when the system goes short on reserves are determined by the ORDC/RCPFC and the marginal cost of energy at the time of the shortage. Even when the shape of the demand curve is essentially a single step, the resulting energy and reserve price transitions will be consistent and gradual. The reason for this is that joint optimization of energy and reserves will continually balance the needs of the system at the lowest cost. Incorporating the both energy balance and reserve requirements in a single solution will ensure that the tradeoff between energy and reserves is accurately captured through both the energy and reserve clearing prices.
Below is a high-level illustration on the market-clearing concept behind using an ORDC/RCPFC. The figure illustrates that as system conditions tighten and PJM must re-dispatch to maintain energy and reserve requirements, the cost of reserves will increase along the vertical segment of the curve. The clearing prices for reserves under normal operating conditions such as this will be solely a function of the cost of energy on the system and offers and opportunity costs of the resources being assigned reserves. The penalty factor price only impacts the reserve and energy prices when the system is short on reserves. This will force a market-clearing along the horizontal segment of the ORDC/RCPFC.

Comment [A28]: This is true, in part, up to the point of scarcity, after which, depending on the implementation, the price can jump very significantly. More generally, with or without this mechanism, LMPs will be volatile in any given hour, if looked at on a 5 minute basis. The overarching goal in all of this is to have price signals that are consistent with the security constraint dispatch solution and to have a mechanism that reflect actual operational practice.

Comment [A29]: This can trigger a significant price jump, depending on the method of marginal unit selection and how prices are formed relative to that marginal unit under conditions of scarcity.

Comment [A30]: Need to make sure that transient issues, such as morning pick up, do not trigger “scarcity” action. This mechanism must be used to represent operational practice, not distort it.

It should be highlighted that when the system is not short on reserves, the prices for energy and reserves are met through virtually the same market mechanisms used today with the exception of the energy and reserve markets being jointly optimized and reserve prices being computed every 5-minutes with energy as opposed to hourly. The ORDC/RCPFC only impacts price calculations in the event of a reserve shortage. With respect to transparency, as the system approaches a reserve shortage condition, there are two consistent price signals being sent to market participants: an increasing energy price and an increasing reserve price which stands in contrast to the current mechanism where the energy price is transparent, but

Comment [A31]: Need to fix the marginal unit designation issue (the issue with inflexible resources) to make this generally true.

reserve costs are not transparent due to after-the-fact opportunity costs payments that are known only to those market participants receiving them.

Additional information regarding price transitions when using the proposed methodology can be found on the SWPG website (http://www.pjm.com/committees-and-groups/working-groups/~/media/committeesgroups/working-groups/spwg/20090821/20090821-item-06-gradual-price-increase.ashx).

Implementation Details: Reserve Requirements and Measurement

The discussions during the SPWG process have resulted in a consensus proposal to focus on current requirements for Synchronized Reserves and Primary Reserves to which PJM operates today. The Synchronized Reserve requirement for a region is equal to the largest contingency while the requirement for Primary Reserves is equal to 150 percent of the largest contingency. While the possibility of adding a requirement for 30-minute reserves in real-time operation was widely discussed, there was not enough support from stakeholders. Given that PJM does not operate to a 30-minute requirement in real-time today, a majority of stakeholders did not see the immediate need to add a 30-minute requirement. The implication of operating to a Synchronized and Primary Reserve Requirement is that there will be a separate ORDC/RCPFC for each reserve requirement in each region.

Measurement of reserve quantities also needs to be improved. Although no major enhancements have been made yet, the SPWG has recognized the need for accurate reserve calculations given the implications on market prices. The SPWG has requested that PJM engage the Operating Committee (OC) to develop enhancements to generation and demand resource parameters. PJM addressed the OC on this at the August 14, 2009 meeting. Discussions on this topic continue.

Implementation Details: Reserve Regions

The SPWG arrived at a general consensus that there need only be two reserve regions: RTO and Mid-Atlantic plus Dominion for which there are Synchronized and Primary Reserve requirements. The RTO requirements for Synchronized Reserve will usually be about 1320 MW and the Primary Reserve requirement will be approximately 2000 MW. The Mid-Atlantic and Dominion reserve regions have been combined as they are electrically defined as those busses that have a 3%, or greater, raise help distribution factor on the APSOUTH reactive transfer interface. The combination of the Mid-Atlantic and Dominion regions into one region will allow total reserves requirements, whether met by internal resources or imports from the rest of the RTO across the AP South Interface, for the combined region to be equal to the current Mid-Atlantic requirements of approximately 1150 MW of Synchronized Reserve and 1700 MW of Primary Reserve.[2] Additionally, PJM will ensure that Dominion's obligation under the VACAR RSG is met by ensuring that at least 423 MW of contingency reserve is maintained in the Dominion zone which can also go toward meeting the regional reserve requirements. With two reserve requirements and two reserve regions, there will be four separate ORDC/RCPFC defined by each reserve requirement in each region.

Implementation Details: Reserve Markets

[2] 4 The current combined Mid-Atlantic and Dominion primary reserve requirement is 1700 plus 423 or 2123. The new combined region helps to reduce the amount of reserves needed.

Comment [A32]: Consensus was on 10 minute reserves

Comment [A33]: The objective of the mechanism should be to internalize actual dispatch practice into the security constrained dispatch software solution, not simply to increase price through additions of superfluous operational constraints.

Comment [A34]: This is not necessary. Violation of one can be violation of the 10 minute reserve requirement, which eliminates the stacked curve issue.

Comment [A35]: This is a threshold issue. Absent accurate measures of reserves, there should be no plans to implement this mechanism in any form. The success of this approach requires accurate measures of reserves.

Comment [A36]: This issues has not been fully vetted

Comment [A37]: This approach needs more discussion.

Comment [A38]: The MA proposal is that these two requirement in each region can be made into one effective requirement for each reason.

PJM currently operates a market for Tier 2 Synchronized Reserves, and PJM is proposing that the synchronized market rules remain largely unchanged except for implementing the joint optimization of energy and reserves. However, in order to price Primary Reserves which can be satisfied by Synchronized Reserves or other 10-minute non-synchronized resources, PJM proposes to establish a formal product market for 10-minute Non-Synchronized Reserves. The market-clearing price for Synchronized Reserves will always greater than or equal to the market-clearing price for 10-minute Non-Synchronized Reserves as any synchronized reserves can satisfy both the Synchronized and Primary Reserve requirements (product substitution), but 10-munte Non-Synchronized can only satisfy the Primary Reserve requirement. PJM also proposes the 10-minute Non-Synchronized Reserve product be a cost-based market which means that offers to provide 10-minute Non-Synchronized reserves will be zero since the cost of standing by unsynchronized to the grid is zero. The 10-minute Non-Synchronized Reserve market will only have a nonzero price when Synchronized Reserves in excess of the Synchronized Reserve requirement are needed to meet the Primary Reserve requirement, re-dispatch is necessary to maintain the Primary Reserve requirement, or there is a shortage of Primary Reserves.

Comment [A39]: This is not necessary for scarcity pricing. In addition, there is no current accurate measurement of such reserves.

Rationale for Setting Penalty Factor prices on the ORDC/RCPFCs

The key criteria in constructing the ORDC/RCPFCs should at a high-level be to set targets at the desired market quantities and set prices such that they elicit an appropriate response given system conditions. Many other factors need to be considered in the ORDC/RCPFC construction but at a high-level these should be the goals. Although the ORDC/RCPFC only explicitly impacts LMPs during actual shortage conditions, the price associated with the ORDC/RCPFC represents the willingness to pay for a specific reserve product in a specific region which means that if set too low it will force the system short reserves based on economics as opposed to a true reserve shortage condition. At the September 22nd 2009 SPWG meeting PJM presented a set of proposed curves for consideration by the stakeholders. These curves were intended to meet the aforementioned high-level goals but also take into account other factors.

Comment [A40]: This LMP impact does not have to be set this way.

1. The current offer caps for energy existing for resources in the market of $1000/MWh and its influence on the maximum opportunity cost for resources providing reserves during stressed system conditions.

Comment [A41]: PJM has not demonstrated that in a market where the highest offer price is $1000, that opportunity costs for providing reserves must exceed $1000. The point of PJM statement is unclear.

2. The effects of continued market power mitigation.

Comment [A42]: Under the current scarcity mechanism, prices at the "marginal" bus are capped at $1000. During scarcity, the price is set based on the highest, uncapped, priced unit running. During the last scarcity event, prices went to $1000. Scarcity was clearly reflected in the energy price, and resources responded. PJM has not provided evidence that the $1000 price cap has prevented the reliable operation.

3. The maximum acceptable price to be paid for a given product.

4. Other associated products for which there may be substitution. For example, Synchronized Reserves may be substituted for Primary Reserves should it be either more economic or nonsynchronized reserves are not available.

Comment [A43]: They are substitutes, but this can be as easily modeled as minimum thresholds within a primary reserve requirement. This would eliminate the need for separate clearing prices.

5. When today's emergency procedures are called and what the intent of those declarations are.

Comment [A44]: It is not clear what is intended by this statement. Emergency procedures are intended to maintain the system in conditions of shortage. Under these conditions the system is out of resources. Once a scarcity price is decided upon, the goal should be a mechanism that maintains the signal through the use of the voltage reductions or manual load dumps, so long as these measures are needed to maintain the system.

6. Demand that is stilling willing to consume energy beyond the historic $1000/MW maximum prices we see today during scarcity events.

Comment [A45]: DR to date has responded well below $1000. It has not been demonstrated that resources priced above $1000 are needed to maintain 1 in 10.

With the existing $1000/MWh offer cap on energy offers from all resources, the highest prices PJM experiences today, absent local congestion and losses, is $1000/MWh. The $1000/MWh energy offer cap is crucial to defining the ORDC/RCPFCs because it provides a good estimate of the maximum opportunity

Comment [A46]: The offer cap does not limit prices to $1000.

cost that can occur for reserves and also what prices likely need to be prior to declaring any emergency procedure.

From an opportunity cost perspective, it is theoretically possible when considering congestion and losses that the maximum opportunity cost for a resource to provide reserves is greater than $1000/MW. This is usually not likely given that opportunity costs are net of the reserve resource's actual offer price and during stressed system conditions, offers on reserve resource's will likely be greater than $0/MW. That being said, the penalty factor needs to be high enough such that it will enable PJM to assign and price all reserves available even under the most strained system conditions. As an example, on August 8th, 2007, reserve clearing prices were posted as at or near $0/MW even though after-the-fact opportunity cost payments were in the $850-$900/MW range. In short, if the penalty factor is not set somewhere at or above this range, PJM would not assign reserves to these resources which would result in decreased system reliability and compliance issues.

From an emergency procedures standpoint, the $1000/MWh offer cap is also significant. Historically a Primary Reserve Warning, which indicates a shortage in Primary Reserves, has been almost immediately followed by a Maximum Emergency Generation declaration. It is also important to consider that emergency DR resources, which include resources with $1000/MWh offer prices, are deployed hours ahead Primary Reserve Warning given the notification required for these resources. Bringing Maximum Emergency Generation into the operating capacity coincident with a Primary Reserve shortage means that at that point all economic capacity up to the $1000/MW offer cap has been exhausted to meet energy balance and reserve requirements and now PJM is relying on emergency capacity to continue to maintain energy balance while attempting to maintain reserves. This directly correlates to system prices because they should reflect the full utilization of economic capacity up to $1000/MWh and should potentially exceed that value to incent other energy only resources and remaining demand response resources with a willingness to pay in excess of the $1000/MWh offer cap to respond to market prices. More succinctly, energy prices should exceed $1000/MWh just prior to or concurrent with the shortage of Primary Reserves in order to attract all resources with offers at or below $1000/MWh to respond.

Enforcing offer-capping even during a reserve shortage, in contrast to the current scarcity mechanism, can in general have the impact of reducing system prices assuming that some on-line resources and the highest cost resources yet to be dispatched may be offer capped. This creates a potential large divergence between the cost-based offers of online operating capacity and offline resources with market-based offers up to the $1000/MW offer cap. The large difference between cost-based and market-based offers creates part of the problem seen in today's mechanism in that once offer-capping is lifted, high market-based offers now set price which causes the characteristic jump in prices seen on August 8th, 2007.

The goal of the ORDC/RCPFC methodology is to bridge the gap between cost-based and market-based offers by injecting a mechanism that can methodically transition prices from non-shortage periods to shortage periods. If supply resources remain offer-capped prior to and during a reserve shortage, the gap between cost-based and market-based offers for resources passing the market power mitigation screen can be very large with the implication that the cost to re-dispatch to maintain reserves can also be very large. Consequently, the penalty factor prices on the ORDC/RCPFC must be set high enough such that they are capable of bridging the supply price gap by permitting offline resources with high priced offers to be called to allow online capacity to provide reserves when there is available capacity to provide reserves. Doing this has a net impact of raising energy and reserve prices due to the increases in the marginal costs of energy and reserve opportunity costs. Setting the penalty factor prices on the ORDC/RCPFC too low in

Comment [A47]: This is not correct. These resources knew they would be paid and were in fact paid opportunity costs based on the actual energy prices.

Comment [A48]: It is important to note that much of these resources have historically responded at prices well below $1000.

Comment [A49]: The majority of emergency MW are priced well below $1000.

Comment [A50]: Agreed. A LMP of $1000 would be sufficient to bring on all resources in the current stack, whether committed or uncommitted via RPM.

Comment [A51]: In addition, PJM attracts imports at prices well below $1000. See 1999 event.

Comment [A52]: This does not follow from the discussion above. A price of $1000 will do this.

Comment [A53]: Either mechanism, one that is capped at $1000 or one that pushes prices to $2700 is designed to account for this, and to encourage competitive behavior.

Comment [A54]: This is not the issue

Comment [A55]: $1000 offer cap solves this issue. The entire dispatch stack is available.

this regard will again result in leaving available, albeit more expensive reserves on the table despite have the physical capacity to provide those reserves. The low penalty factor would cause the system to go short on reserves not for a lack of physical capability, but due to a lack of willingness to pay for the higher priced reserves.

It's important to also note that penalty factors can be set "too high". Setting a penalty factor too high can raise reserve and energy prices significantly while achieving little to no benefit in terms of attracting other available supply-side or demand-side resources to maintain energy balance and reserves. The penalty factors PJM has selected represent what is likely to be the lowest penalty factors that can be used given the market structure that exists today. The value of using higher penalty factors can only be gained through either researching the costs associated with energy only resources that may respond of their own volition to PJM prices or with experience. Its PJM's opinion that the initial implementation of this mechanism and the associated penalty factors should be conservative until further analysis is done and experience is gained.

Comment [A56]: There is no theoretical or empirical basis for this statement.

Comment [A57]: Agreed. Use of a $1000 offer cap meets these objectives.
PJM's proposed use of $2700 is not conservative.

PJM's Proposed ORDCs/RCPFCs

The curves PJM has proposed take all of the previously described factors into account. In addition to those factors, PJM also considered the need for transparent curves that leave no ambiguity in the prices being calculated and also the need for equitable treatment across all regions of the RTO. Below are PJM's proposed Primary Reserve curves for both the entire RTO and the Mid-Atlantic plus Dominion region.
The penalty factors for these curves are $850/MW and the target quantities are 150% of the largest system contingency. The penalty factors are intended achieve the goals of accurately pricing Primary Reserves on the system, providing an advanced pricing signal of an impending shortage and eliciting a response from any available resources commensurate with the shortage. The $850/MW price is set high enough such that it will ensure all Primary Reserves are assigned, thus not sending the system into an economic reserve shortage and also make certain that energy prices exceed $1000/MW prior to a shortage of Primary Reserves. This is consistent with system operations today as a Primary Reserve Warning has historically been a precursor to requesting Maximum Emergency Generation capacity.

Comment [A58]: One of the outstanding issues is still measuring where the system would be on the curve(s) under any of these proposals. Measurement needs to be improved.

Comment [A59]: This should not be a requirement.

The curves shown above provide transparency in that the impact of a Primary Reserve shortage in either region will result in an $850/MW reserve clearing price. When the system is not short, the clearing price will be determined by the supply and demand conditions relative to that market, which is similar to how clearing prices are calculated today. Additionally the curves do not differentiate between regions of the system. A shortage of Primary Reserves in the Mid-Atlantic plus Dominion region is as significant for that region as would exist for the entire RTO should that not have adequate reserves.

Following a similar methodology, PJM also proposed the Synchronized Reserve ORDC/RCPFC displayed below. The major difference between these and Primary Reserve ORDC/RCPFC is that the curves below contain multiple steps. The rationale behind the additional lower priced step is to account for some conditions that may occur on the system that may cause Synchronized Reserves to go into shortage on a temporary basis.

1. *Increased reserve requirements due to transient switching conditions on the system.*
   These increases in the requirement are often characterized as "double spinning" and are a result of switching on the system that could cause the loss of either multiple units or a piece of equipment larger than the normal largest unit. In these circumstances, PJM may be short of meeting the

Comment [A60]: This is handled under the current market mechanism. This is not scarcity and should not be priced as such.

increased requirement but is not in general operating less reliably as non-synchronized reserves may be utilized to cover what is not committed as Synchronized Reserves. For this reason, the initial step on the Synchronized Reserve ORDC/RCPFC is at a lower level. This lower price implies that if the reserves are there and inexpensive, they will be committed. However, if they are either not there or are more expensive, the system is willing to cover the balance with nonsynchronized reserves.

2. *Transient reserve shortages caused by extreme ramping conditions.*
   Tier 1 reserves account for a large majority of Synchronized Reserves on the PJM system but because they are not a firm reserve obligation, they can be converted to economic energy during the hour. This is most prevalent during load pickups when all resources are in general ramping up to meet load. As economic, load following generation ramps up to meet system conditions, there may be brief periods where PJM elects to start synchronous condensers or notify demand resources to cover the reserve requirement as opposed to having dispatchable generation do so. These periods should be transient and should not result in large reserve and energy price swings.

Comment [A61]: This is not scarcity and should not be priced as such.

These curves follow the same general methodology as the Primary Reserve curves with the exception of the multiple steps. The penalty factors again in this case are $850/MW for the same reasons they are for Primary Reserves. Below is a composite curve showing how reserve prices would transition if PJM went short Primary Reserves and then Synchronized Reserves. Although this seems like the logical progression, it may not actually be the case in real-time which drives the needs for product and location based curves with relatively the same pricing impacts. Below is only the composite curve for the RTO. The Mid-Atlantic plus Dominion composite curve would have the same shape with the exception that the target quantities would be relative to that market area. From the combined RTO curve we can see that the penalty factors will not explicitly set market clearing prices until the RTO goes short of 2000 MW of Primary Reserves. Before that point, reserve clearing prices will be set based on supply and demand conditions in that market. Beyond that point, the clearing price for Primary Reserves is set at $850/MW.

Because Synchronized Reserves are a subset of Primary Reserves, the clearing price for this product will always be equal to or exceed Primary Reserves. This is because of the substitutability of these products and the fact that Synchronized Reserves are a higher quality product. Once the system can no longer meet the Synchronized Reserve requirement, the price for Synchronized Reserves will rise to $950/MW ($850 Primary price + $100 Synchronized Reserve penalty factor) and the Primary Reserve clearing price will remain at $850/MW. As the shortage continues to the next large step, the system will re-dispatch to maintain Synchronized Reserves along the vertical segment of the curve and prices will again rise gradually as conditions tighten. When the available Synchronized Reserves dips below roughly 1000MW, the price for those reserves will be $1700/MW ($850 Primary penalty factor + $850 Synchronized penalty factor). At this point, the system can no longer respond to its largest contingency with reserves and non-capacity emergency procedures such as voltage reductions must be invoked. It is at this time that energy and reserve prices must be at their highest.

Comment [A62]: It is not clear how system control would be maintained when there are multiple marginal units. Under conditions of price separation (energy), the opportunity costs will vary by location. This underscores that the primary market is energy. Reserve payments are based on locational opportunity costs.

Considering the $1700/MW reserve clearing price and the $1000/MW offer cap on energy, the theoretical maximum energy price would be $2700/MW. Achieving this price is not likely because the circumstances under which it would occur would be such that both reserve products are short and the resource providing the next incremental MW of energy would need to have an offer of $1000/MW. The goal of graduating price changes and allowing for prices to exceed the current $1000/MW offer cap is to elicit responses from

Comment [A63]: Prices above $1000 should not be the goal. There is no empirical support for this claim.

energy only resources early enough to avoid the calling non-capacity emergency procedures and ever getting to the $2700/MW maximum price except in only the most extreme of circumstances.

Remaining Implementation Issues Requiring Further Development

As mentioned in the opening, there are several key issues that remain unresolved despite the progress made by the SPWG. PJM has presented either options on the resolution to these items or its opinion on the solution. The following section details at a high-level the options or opinions presented to date on each item as well as PJM's opinion on the best resolution to the issue.

Dispatch of Emergency DR Resources

The current deployment method for emergency DR is essentially a bulk request where all resources are requested to curtail at once, independent of price. This method has worked in the past simply because emergency DR accounted for a relatively small portion of the capacity in PJM, less than one percent of the all-time system peak. However, emergency DR accounts for almost five percent of the all-time system peak and therefore can have much more significant impacts on system control and pricing than in the past.

Comment [A64]: Price effects should be a non-issue in this discussion so long as supply and demand fundamentals are reflected in the market. System control is an issue. It is not clear how reductions in load during conditions of system stress would be problematic.

Given the substantial increases in demand-side capacity, a more rational dispatch of these resources, preferably by price and in small increments, is necessary. The ideal solution to this issue would be for PJM to dispatch these emergency resources economically based on submitted strike prices. This method presents issues in that based on existing offers the supply curve would contain a majority of the emergency DR capacity at or near $1000/MWh. This creates a large dispatch tie at that price for which some methodology would need to be identified to cleanly and realistically break the tie. The SPWG has defined several options to more granularly dispatch emergency DR and to handle the large volume of offers at or near $1000/MWh. No decision has been made on which option will be incorporated into the new scarcity pricing design.

Comment [A65]: This approach needs to be squared with the obligations taken by participants in the RPM auction.

Comment [A66]: Locational dispatch should be considered.

There is also a need for PJM dispatchers to understand how many MW of DR resources may have already responded to price so as to better understand how many MW of DR they can expect with a call for emergency DR resources. After analysis of the August 8, 2007 scarcity event it was evident that a large percentage of both economic and emergency demand resources had curtailed load prior to the emergency declaration. However, for the current 2009/2010 delivery year, approximately one-third of the almost 7000 MW of DR capacity is also registered in the Economic Load Response Program. While the percentage of total emergency DR that may respond to price is less than in 2007, the total MW capability is much greater. The SPWG is working towards developing a methodology by which PJM can receive real-time information on demand resource capacity. This information needs to available to PJM in real-time in some fashion.

Comment [A67]: This uncertainty is one, among several reasons, that emergency DR must be handled as simple changes in load once called, rather than a measurable administrative act that must be offset in the mechanism.

Pricing Impacts of Deploying Emergency Capacity

It is important to recognize that the initiation of any emergency procedure, from deploying emergency DR, calling on Maximum Emergency Generation, voltage reductions, or even calling for a manual load dump, will have the net effect of creating reserves on the system which will directly impact price. In the case of emergency capacity, DR and generation, the net effect is either a reduction in load or increase in generating capacity, respectively, that will free up other resources on the system to provide reserves. In the ORDC/RCPFC methodology, increasing reserve quantities through out-of-market actions such as emergency procedures can counterproductively reduce prices even though the system is in an emergency.

For some emergency procedures that will impact prices but do not directly have a price associated with them, some intervention must be made to ensure price performance during the emergency conditions. In the case of deploying emergency capacity, DR and generation, pricing impacts can be attained through the higher priced resources being permitted to set system prices when deployed. For generating capacity the solution is relatively simple in that the higher priced emergency segments for online resources and those offline resources called online via the Maximum Generation declaration should be permitted to set price as if they were part of the normal operating capacity. This will have the impact of raising the energy and reserve prices commensurate with the emergency declaration. For emergency DR resources the solution is not a clear.

Comment [A68]: Not in the case of DR that does not meet the criteria for setting price under the tariff.

Comment [A69]: Capacity recalls need to be addressed. They are not mentioned here.

Comment [A70]: Measures that have to be accounted for in the mechanism: Voltage Reductions and Manual Load Dumps.

There are several complications in having emergency DR resources that do not have the required realtime, interval metering and two-way telemetry, which make up the vast majority, set price after being deployed. Those resources that do have the aforementioned telemetry should be eligible to set price and are currently permitted to in the PJM Tariff. However, these resources make up a very small percentage of the emergency DR capacity which poses an issue that must be addressed. The complications created by this are detailed below. First, a resource can only set price when it is online and following PJM's dispatch direction. In the case of emergency DR resources, it cannot be clearly determined when the resources have responded, let alone are following dispatch and marginal. Second, emergency DR resources are often aggregated at the zonal levels, but prices are calculated at specific nodes. If an aggregated resource in a zone were deemed marginal, which at this point cannot be determined, at which bus in the zone would it set price? Setting a flat price across the zone would have counter-productive results in that it would send a flat signal to the zone and would require the manual dispatch of resources to maintain local constraint control.

Some options to ensure price stability during the deployment of emergency DR that were discussed previously at the SPWG were to invoke an offset to the reserve quantity based on the anticipated emergency DR response, or, to set a floor on the reserve price such that additional reserves created by the load reduction do not significantly reduce prices. Both of these methods create complications. Utilizing an offset would be extremely difficult to do accurately given the lack of real-time information on emergency DR capacity and could result in large measurement errors that adversely impact prices and system reliability. Setting a price floor on reserves could present similar problems discussed above in that it could potentially force energy prices into a range that would incent generators to perform beyond what the system requires given that load is reducing which could also lead to control issues.

Comment [A71]: Emergency DR should be called if needed, and any subsequent changes to load should be, in the context of the model, be attributed simple changes in load (this reduction is load has already been paid for, and will be further compensated via energy prices), not the use of emergency procedures such as a voltage reduction with no market valuation.

The most important component to ensure both price performance and system reliability when deploying emergency DR is to get the dispatching mechanism correct. This mechanism needs to be simple enough for all CSPs to implement but allow enough granularity so that PJM operators know what response they will get when they ask for a curtailment and allow them to ask for the quantity they need instead of the current bulk deployment mechanism.

Pricing Impacts of Other Emergency Procedures

Non-capacity emergency procedures such as a voltage reduction and a manual load dump will have a similar impact as deploying emergency DR resources in that the net effect is a decrease in load on the system. Initiation of these procedures indicates a much more severe situation in that the declaration of these is only done when PJM is already short on reserves and requires these emergency actions to maintain the ability to serve load on the system.

Some options to incorporate the load reduced by these procedures have been discussed at the SPWG. The main mechanism has been, again, similar to the accounting for emergency DR, apply an offset to either the reserve quantity or requirement to account for the out-of-market change in system conditions.

Counting Emergency Capacity Resources as Reserves

The SPWG has discussed at length what should be included in reserve calculations and has more specifically focused on whether all RPM capacity should be counted as reserves as long as it meets the 10-minute response criteria required for both Primary and Synchronized Reserves. Emergency generating capacity can be broken into two groups, emergency segments on resources that are already online and operating, and fully emergency resources that will only come online once a Maximum Emergency Generation emergency procedure has been declared. Today, these two types of emergency capacity are handled differently.

• Emergency segments are not always included in reserve calculations but can be at the asset owner's discretion. Each generation resource can bid in a SpinMax quantity on an hourly basis that indicates to PJM the maximum output achievable during a Synchronized Reserve event. The SpinMax value must be greater than or equal to the Economic Max. In the case that it is greater, some capacity on the emergency segment is included as reserves. In the case that it is equal, no capacity from the emergency segment is included.
This functionality essentially allows the asset owner to define what capacity on their resource can be counted on as 10-minute reserves. It leaves no ambiguity in the reliability of the reserves being counted.

• Fully emergency resources are never counted as reserves regardless of if they are capable of starting in 10-minutes. Resources bid in as Max Emergency are often at a higher risk of failing to start or suffering a critical failure during operation which would make them less reliable reserve resources that PJM operators are not willing to rely on.

In general, emergency DR capacity is not counted on as reserves. DR resources however can provide reserves should they offer and clear in the Primary or Synchronized Reserve markets.

The argument at the SPWG for including all RPM capacity meeting the 10-minute response criteria, emergency or economic, as reserves is essentially that the resources are receiving an RPM payment and are being relied upon to, and paid for, delivering their capacity during peak conditions, but from an operational standpoint it is not clear if such resources can be relied upon if they are declared as maximum emergency.

Conclusion

PJM proposes an ORDC/RCPFC methodology discussed in this document and at various stakeholder meetings to bring PJM into compliance with Order 719 requirements regarding pricing during operating reserve shortages, and to improve market pricing during all system conditions and also enhance operational reliability. The new mechanism will allow for more cohesive reserve and energy prices and a more consistent, economic and rational dispatch profile both during normal operating conditions and times of reserve shortages.
Provided below is a brief summary of PJM's proposal and position on the open issues detailed in the body

Comment [A72]: The offset should not be applied to emergency DR.

Comment [A73]: But emergency resources running as energy should be counted as energy. The mechanism should reflect operational practice.

Comment [A74]: If correct, should not be capacity resources.

Comment [A75]: But Emergency DR "provides" an actual (not artificial) reduction in load.

Comment [A76]: These resources should be looked upon as supplying energy when running, and should be considered as part of the dispatch stack under emergency conditions.

of this document.
• Implement a methodology incorporating an ORDC/RCPFC and a real-time joint optimization of energy and reserves.
• Continue to execute the Three Pivotal Supplier test at all times when committing resources for transmission control.
• Define the static reserve region of the Mid-Atlantic plus Dominion area of the RTO. This will technically be any pricing nodes in the RTO with a greater than or equal to 3% raise help distribution factor on the APSOUTH reactive transfer interface.
• Implement a 10-minute Non-Synchronized Reserve market to procure and compensate nonsynchronized reserve resources for helping meet the Primary Reserve requirment.
• Model one ORDC/RCPFC for each product in each region (four total curves).
• Utilize the capability of the joint optimization to have 5-minute dispatchable reserve assignments where feasible.
• Calculate 5-minute prices for energy, synchronized reserves, non-synchronized reserves and regulation.
• Implement the ORDC/RCPFCs defined in this document as a conservative starting point.
• Re-evaluate the ORDC/RCPFCs after the summer of 2011 and make adjustments as needed.

Page 6: [1] Comment [A23]	Author

In order for the market to clear with no Tier 2 indicates that software thought it had more than enough Tier 1 going into the hour to meet its sync requirements. Under these circumstance, the hour ahead Tier 2 should clear at zero, as there would be no demand for Tier 2.

To the extent that resources had to be dispatched to provide additional reserves *within* the hour, those resources would be paid their opportunity cost (effectively creating a within hour Tier 2 resource).

Page 6: [2] Comment [A24]	Author

This does not mean that the resources were only paid $6. There was a true up based on actual within hour opportunity cost. See Table. 81 MW of Reserve was bought in the Tier 2 market at a price of $6 in hour beginning 17 (last hour of the scarcity event), but Tier 2 reserves were paid $32,326 which means it was paid (on average) $395.72 per MW after adjustments.

Page 6: [3] Comment [A25]	Author

In part this result was due to misspecification of the Sync Market. The role of constraints limiting the deliverability of reserves was not sufficiently captured. Specification and measurement error.