Some Thoughts on PJM Capacity Performance Product Proposal
and an
Alternative Straw Proposal

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Submitted on his on Behalf

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1) PJM has identified another basic flaw in the implementation of the RPM design. This is the mismatch between basic planning assumptions for capacity performance and availability, and the actual performance and availability of the capacity products allowed to be offered and actually purchased. In approaching the solution, PJM makes a fundamental misstep. It focuses its attention on the fact that some of the capacity products do not match planning assumptions (i.e. base capacity). However, it completely misses the most obvious conclusion, that other products (Limited DR, Extended Summer DR and Annual DR) also do not match the basic planning assumptions, and in fact are far less in synch with the basic planning assumptions used in the PRISM model that is used to set the IRM reliability target.² Any solution must address both observations. PJM has not done this.

2) It is worth considering the source/cause of these collective (not single) deficiencies before attempting yet another patch on the RPM structure. From my perspective there are three principle causes of the mismatch in assumptions and implementation.

   i) The first, and most obvious, is that the PRISM model used to calculate the IRM assumes a single, homogeneous, annual product with random outages. There is no mechanism to directly include the impacts of the multiple products that PJM is proposing in PRISM, nor their collective impact on target reliability.³

¹ These are my own comments and do not necessarily represent the views of any of my clients.
² Hopefully it is obvious that if all Limited and Extended Summer products were Annual (in excess of 10,000 MW of supply), there would not have been any reliability concerns last winter despite the poor performance of some thermal units.
³ The mismatch between PRISM assumptions and the use of multiple inferior products exists even in the current product structure. All impacts on the system LOLE from such products are “post processing” to the basic reliability analyses. The net effect has been a material increase in LOLE, likely in excess of the stated 10% due to the inclusion of Limited DR within the “window” estimated for allowable Extended Summer. Last winter’s events suggest the actual LOLE may be materially higher.
ii) Second, the VRR Curve initial design logic also assumed a single homogeneous product in all analyses used to consider the location and shape of the curve, as well in the underlying theory relied on to set the “anchor” of the curve at the reference net CONE. Price formation using that design but coupled with multiple inferior products inevitably under values the single superior reliability product. The exact distortion is unknown.

iii) Third, the RPM model and associated VRR curve was predicated on the purchase of 100% of forecast load reliability requirements, and did not include (as it should not have done) the price discrimination practice of mandating 100% of supply make offers, but setting demand at a level reflecting only 97.5% of the forecasted demand.  

3) Collectively, PJM’s departure from these basic underlying principles has severely harmed RPM’s ability to accomplish its basic functions. The acceptance of inferior sub-annual products, combined with explicit price discrimination via understating demand, has understated prices and capacity revenues on the order of $10 billion per year for an extended period.  

It is important to keep this cumulative perspective in mind in considering what to do next. PJM’s inconsistent structure (between assumptions and implementation) and the resulting under-pricing has had a cumulative effect of distorted and suppressed prices that over the last few years have lead to unnecessary churning of the capital stock via retirements, unnecessary new entry, and modifications in maintenance and unit availability. At the same time the inclusion of inferior products, and no clear performance requirements for traditional products, has reduced system reliability.

4) Recognizing these basic assumptions and problems leads to what I believe is a much simpler and superior structure for improving RPM. One that I believe will be better integrated with the basic planning assumptions, and should, unlike what PJM is suggesting, come much closer to achieving a target 0.1 LOLE. Implementation of this proposal is also straightforward. The following is a high level view of what I believe would be a superior set of modifications that accomplish PJM’s stated intent, while resolving other fundamental flaws in the RPM design. As usual, when offered at such an aggregate level, it must be understood that there will inevitably be more detailed adjustments needed.

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4 It should be obvious that there will always be surplus capacity and thus price suppression when only 97.5% of expected load is considered, unless annual load growth exceeded 2.5%. Even then, with higher growth it would still truncate the supply curve/demand curve intersection at values too low.

Suggested Solution.

5) Straw Proposal. While any final proposal will need additional fine-tuning, I have put together a simple straw that I think remedies the major flaws in the current design and resolves the concerns that PJM has raised.

A) Single Product. The most important element is the establishment of a single reliability product. Limited DR and Extended Summer DR would be eliminated (phased out per a transition plan). Annual DR would be defined as per the current PJM Capacity Performance (CP) proposal. Annual “traditional” generation would be defined similar to PJM’s CP proposal for the CP product. There would also be a transition period for traditional generation to make appropriate adjustments to fuel supply/storage and winterization or other capital changes. Transitional requirements would be defined. Most of the proposal could be implemented immediately, but as usual there are equitable considerations that justify a phased transition.

   i) The annual products will be defined similarly to CP proposal, exceptions to these may be discussed, but include at minimum added fuel reliability/availability and weatherization.
   ii) Proper certification and verification will be required of increased performance related to the new CP specifications.
   iii) The reference unit Gross CONE will be modified to conform to the CP product definition and VRR Curve modified accordingly.
   iv) Limited and Extended Summer DR would be eliminated. Annual DR either kept or moved to Price Responsive Demand if applicable state tariffs are implemented.
   v) Transition provisions implemented for existing cleared Limited and Extended Summer products that are to be removed permanently. (Annual DR as well if moved to PRD)
   vi) Transition provisions for the movement from “base” to CP resources, e.g. the new annual resource

B) Clearing. Clearing will be simplified, based on traditional planning parameters against the single product. Basically this would be the status quo without multiple products. This is the only structure that is consistent with the basic RPM underlying assumptions.

C) Holdback. The 2.5% holdback (short term resource procurement target) in forecast demand would be eliminated from the BRA (demand increased) All

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6 Alternatively the annual DR product could also be eliminated, and allowed to participate via PJM Price Responsive Demand provisions.
7 This may be moot given the September 17, 2014 decision of the DC Court of Appeals regarding Demand Response.
forecast load will be included in the BRA. Again the removal of this explicit price discrimination is essential and inherent in the underlying assumptions for RPM.

D) Penalties.

i) With the above structure, and an M&V program for fuel security and weatherization (assuming some certification as well), it is not clear why a different penalty structure is needed from the status quo. Suppliers have a huge incentive to be available in high priced alert hours. This typically is the period where the majority of energy operating margins are captured. It is irrational for parties with a legitimate and reliable capacity resource not to attempt to maximize performance during alert and emergency hours.

ii) However this performance/no penalty conclusion is predicated on a resource actually meeting appropriate fuel security and technical performance requirements. Suppliers failing the M&V requirements in violation of an associated certification would forfeit all revenues and be subject to referral to the FERC.

iii) If a penalty structure is selected, it is important that it be known ex ante to the auction so that offers can appropriately reflect this cost exposure, rather than penalties being set at an ex post value based on the clearing price. This allows the opportunity for the direct incorporation of any associated risk, change in Gross CONE, cost of credit etc. I would suggest the use of system net CONE divided by some historic average of alert and emergency hours as the penalty for hourly unavailability during alert hours ($/MWh). This would mean a high multiplier with low prices and a low multiplier with high prices, but over time, match expectations about target revenues with penalties.

E) Offer adjustments in presence of additional penalties.

i) PRISM and the associated basic planning assumptions assume approximately 7% random outages across all supply. The 7% represents the system wide EFORd. Thus an assumption of comparability with planning inputs (not a risk premium as characterized by PJM) would allow offers to include 7% of the product of net CONE divided by the average alert hours. Such an adjustment merely holds suppliers harmless, on average, against the type of penalty suggested above so long as they perform consistently with planning assumptions. (This would be modified in parallel with any final determination of penalty metric, but still include the acknowledgment that the system average EFORd is “built in” to the reliability targets.) (Similarly, without a penalty structure, this “adder” would not be needed.)

ii) A risk premium may also be justified based on the variance around the 7% value. E.g. the one sided up-side tail for x standard deviations times the
product of net CONE divided by average alert hours. For example if the one sided portion of the standard deviation were 1.5%, and it was assumed that X was “settled” at 1, than an additional 1.5% of the alert and emergency hours related penalty costs could be included in an offer. This concept deserves further consideration, and interacts with other concepts that have been suggested regarding shifts in total compensation between over and under-performing units. Depending on how these concepts are developed as a package, such an additional premium may be unnecessary.

F) **Excused outages.** There would be no excused outages during peak hours other than for transmission outages outside of the control of the generation facility.

G) **Must Offer.** Existing units would be expected to have a must offer obligation for the new annual product. Such an offer may include necessary APIR costs for conversion. The offer quantity in terms of operating performance is the unit ICAP, while the RPM model would continue to be solved based on UCAP. ICAP would also be used for the determination of penalty quantities, if penalties are included. A waiver would be provided for units that can justify not making the required changes/investment to qualify as the new CP product and would retire.