UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Centralized Capacity Markets in	)	
Regional Transmission	)	Docket No. AD13-7-000
Organizations and	)	
Independent System Operators	)	

Comments of

Roy J. Shanker Ph. D.

Independent Consultant

September 25, 2013

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1) My name is Roy J. Shanker. I am an independent consultant with almost forty years of experience in energy markets, with most of that work dedicated to the electric utility industry, and for the past 18 years to the development of the market designs for independent system operators ("ISOs") and regional transmission organizations (RTO's).[2] I am appearing here today as an individual and am not sponsored by any client. I would like to thank the Commission for inviting me to speak and present these comments.

2) My first reaction in seeing the Commission Notice of Technical Conference in June was the famous quotation from Yogi Berra: "It's déjà vu all over again".[3] The Commission has a long history of addressing capacity adequacy issues, and has repeatedly found a need for transparent, non-discriminatory and well-designed markets and market mechanisms to assure the economic entry of new generation and retention of needed existing capacity resources.[4] It has similarly rejected

[1] Dr. Shanker is an independent consultant representing many participants in organized markets. These comments are his own, are not sponsored by any client, and do not necessarily represent the position(s) of any of his clients.

[2] A summary of my relevant work and testimony is attached to a recent affidavit I offered before the Commission, see e.g Prepared Direct Testimony of Roy J. Shanker Ph.D. on Behalf of DC Energy LLC and Vitol Inc, March 7, 2013 EL13-47

[3] Yogi Berra was commenting on Mickey Mantle and Roger Maris hitting back-to-back home runs repeatedly. With this in mind, much of the content of this discussion draws on my previous comments, affidavits, and testimony that have been presented to or filed with the Commission.

[4] The need for capacity markets is well documented in testimony submitted to the Commission and in the Commission's own orders establishing such markets in all three of the Eastern RTOs. *See, e.g.*, *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079, *order denying reh'g and approving settlement*, 117 FERC ¶ 61,331 (2006), *order on reh'g and clarification*, 119 FERC ¶ 61,318 (2007); *Devon Power LLC*,

market design elements that it has found to be unjust and unreasonable vis-à-vis these principles.[5] In the following comments, I have tried to first offer some thoughts on general principles and concepts related to capacity market design, and where appropriate, add some specific examples of situations in which these principles are not being followed. After that, I present short responses to the five questions separately put forward in the August 23, 2013 Supplemental Notice.

3) Starting from general principles, the first overarching question with respect to an adequacy construct is whether reliability in terms of capacity adequacy is a market outcome, or an input/constraint that underlies the market design? If reliability is an outcome, then there is no need for a capacity market, as the level of reliability is what parties voluntarily pay for. Resources will be built in response to demand, considering spot market requests for power and longer term supply agreements. Total supply will be a function of willingness to pay. Indeed, the notion of reliability is not well defined in a world where there is no specified requirement.

4) But the notion of a voluntary and variable outcome for adequacy and reliability has no place in our current regulatory, legal, and market regimes. In the United States, the unambiguous answer to the overarching question is that reliability in terms of capacity/supply adequacy is an input to or constraint within the market design. In every Commission-jurisdictional market of which I am aware, adequacy is required to meet some variant of a target loss of load expectation or probability, typically one day in ten years.[6] Thus, resources are consciously procured to meet infrequent peak demands based on the exogenously set reliability standard. That is, the parties responsible for system adequacy consciously contemplate a world in which some units may seldom, if ever, operate in order for the overall market to be assured of sufficient supply in these low probability events. Similarly, most markets have explicit offer caps on energy supply pricing and energy pricing mitigation in times of scarcity. In combination, infrequent operation and capped/mitigated energy offer prices result in a situation where low capacity factor units earn little if any returns above their marginal operating costs and have little opportunity to recover fixed costs. I have referred to this inherent property of markets where adequacy is an input constraint as the "missing money" issue, which ultimately requires some mechanism to allow payments outside of the energy market to attract new capacity resources and retain needed existing capacity resources.

5) Note that while modifications to the energy market such as the operating reserve demand curve being pursued by the Electric Reliability Council of Texas (ERCOT) would obviously improve real time energy price signals, they would not obviate the

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113 FERC ¶ 61,075 (2005), *order approving settlement*, 115 FERC ¶ 61,340 (2006); *New York Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201, *reh'g denied*, 105 FERC ¶ 61,108 (2003); *New York Indep. Sys. Operator, Inc.*, 89 FERC ¶ 61,109 (1999), *order on reh'g and clarification*, 90 FERC ¶ 61,085 (2000).

[5] *See*, *e.g.*, *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 (2006).

[6] While specific metrics vary, the generally accepted and targeted reliability adequacy objective is to limit outages that result from load exceeding generation to one day or occurrence in every ten years.

need for a capacity market. Indeed, the best solutions are where more efficient real time energy prices are combined with an appropriate capacity mechanism.

6) The issue that we are again addressing today is the best way(s) to achieve that "appropriate capacity mechanism" and what associated design criteria that should be utilized. Fortunately, most of the "heavy lifting" with respect to this issue has already been done, presented to, and endorsed by the Commission in previous proceedings and decisions, some going back over a decade. In particular, the initial testimony of Dr. Steven Stoft that was presented in *Devon Power LLC*, Docket No. ER03-563 (also known as the New England locational ICAP proceeding) contains an excellent discussion of the overall use of central auctions and the associated use of a demand curve, including the slope and point of inflection of an efficient demand curve. These concepts are also discussed in the Initial Decision by the Administrative Law Judge in that proceeding, that in large part approved ISO-New England Inc.'s (ISO-NE) 's proposal.[7] Likewise, the August 31, 2005 filing by PJM Interconnection L.L.C. (PJM) to establish the Reliability Pricing Model (RPM) and the associated testimony in support of PJM's filing in Docket Nos. EL05-148 and ER05-1410 contain an excellent summary of the rationale behind several of these key design criteria, including the forward commitment, the downward sloping demand curve, and locational clearing, many of which are reiterated in the Commission's order approving the RPM settlement issued on April 20, 2006. [8]

7) I believe that these filings and associated orders set forth the building blocks for resolving virtually all of the questions under discussion here. In general the content was solid, and but for the erosion of factual conclusions by settlement, which in many instances reflected an incremental "creep" towards discriminatory results, the referenced orders and underlying filings resolved many of the questions that are still in dispute or are being considered yet again in this technical conference.

8) My review of these previous capacity market proceedings and the associated orders identified four general principles and a number of specific sub-areas that are relevant to addressing the items for this conference. As I stated in my July 1, 2010 testimony in Docket No. ER10-787:

> I have identified four general requirements for capacity markets to succeed—each based on bedrock economic theory. These core principles may be summarized as follows:
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> > Principle 1—Capacity markets must permit sufficient revenue to average true net CONE over time in order to attract new entry and retain economic generation.

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[7] *Devon Power LLC*, Prepared Direct Testimony of Steven E. Stoft on behalf of ISO New England Inc., filed Aug. 31, 2004, Docket No. ER03-563-030; *Devon* Power *LLC*, 111 FERC ¶ 63,063 (2005).

[8] *See*, *e.g.*, *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 (2006).

> Principle 2—Capacity markets must reflect all locational and reliability constraints in order to accurately reflect the true value of generation assets.
> Principle 3—Capacity markets must compensate similarly-situated generation assets consistent with the law of one price in order to prevent undue discrimination and inefficient price signals that stifle competition.
> Principle 4—Capacity markets must mitigate both buyer and seller market power.
>
> Without ever formalizing these requirements, the Commission, in a series of orders, has recognized that these principles are necessary attributes of capacity markets. These principles transcend any notion of regional differences in implementation, and must be incorporated in some fashion into any working capacity market design.[9]

9) *First,* over time, compensation must be sufficient to attract new entry and retain existing economic generation.[10] This means that, on average and over time, the recovery from the bulk power markets for energy and capacity must result in payments expected to be equal to the cost of new entry.[11] Implicit in this principle is the fact that if prices will be lower than average some of the time, they *must* be higher than average during other periods. This property must be present in any resulting market design. The Commission has also expressed a preference for designs that reduce price volatility, although this has not been a requirement.[12]

10) This preference for reduced volatility is at the heart of the considerations for the use of a demand curve and the institution of forward based capacity markets that I believe are the major building blocks of an effective capacity market. As I have repeatedly stated, and as excellently discussed in Dr. Stoft's testimony cited above, the key property of a downward sloping demand curve is that it can be used as a control mechanism for both quantity and speed of adjustment for total capacity adequacy resources. As the demand curve is shifted up and down (right and left), the targeted capacity sought can be adjusted. Indeed it was a key insight, captured

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[9] *ISO New England Inc.*, Testimony of Roy J. Shanker Ph.D. on Behalf of New England Power Generators Association at 5-6, filed July 1, 2010, Docket Nos. ER10-787-000, *et al.* ("Shanker Testimony").
[10] *See ISO New England Inc.*, 125 FERC ¶ 61,102 at P 43 (2008) ("The purpose of the New England FCM is to attract and retain sufficient capacity to maintain ISO-NE's Installed Capacity Requirement . . . ."), *order on reh'g*, 130 FERC ¶ 61,089 (2010).
[11] *See Blumenthal v. ISO New England, Inc.*, 117 FERC ¶ 61,038 at PP 82-87 (2006), *order on reh'g*, 118 FERC ¶ 61,205 (2007) (determining that the long-term design of electric market must be based on competitive outcomes and that over the long- term just and reasonable rates are equal to marginal cost of generation); *Devon Power LLC*, 115 FERC ¶ 61,340 at P 114 (explaining that offers at prices below a resource's long- term average costs, net of non-FCM market revenues, should be mitigated in order "to reset the clearing price to a level that would be expected in a competitive market").
[12] Shanker Testimony at 6-7, citing *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 at P 104 (2006).

by Dr. Stoft and incorporated by PJM in its original filing, that in order to maintain a market based quantity at or above their reliability targets most of the time, the "anchor point" on the demand curve, (where price was equal to an expectation of the cost of new entry) would have to be greater than the specific reliability target for the market area itself. This would allow the market control mechanism (the demand curve) the flexibility to result in quantities that move above and below the anchor point over time, recover adequate compensation, and still meet reliability targets.[13]

11) Similarly, it was recognized that the slope of the demand curve was an important control tool as well. When supplies were short (below the reliability target) it made sense to have a demand curve with a steeper slope, encouraging new entry and retention by a rapid escalation in price. When supplies were in excess, it was logical to flatten the curve, to prevent the precipitous retirement of existing resources due to lower, but necessary, levels of compensation. Indeed, PJM's witness, Benjamin Hobbs built extensive simulations around just these principles to demonstrate the ability of the demand curve to function as a tool for controlling both quantity and volatility in price. All of this emphasizes that the specific values and shape of these types of demand curves relate to the control function, not the marginal value of capacity, in the situation where the reliability target was set as an input to the market design. One of the continuing obfuscations presented to the Commission is the misrepresentation of capacity (or operating reserve) demand curves exact representations of marginal values of reliability versus as control mechanisms.

12) In my opinion, one of the specific harms of the settlement process involving PJM's RPM implementation was that the demand curve was modified in such a manner as to directly invert these important design control properties. In comparison to the original proposal, the slope of the demand curve was flattened to the left of the "anchor point" and steepened to the right. The consequences of these alterations are price signals that are exactly the opposite of the desired control properties. This results in greater volatility, and an increased likelihood for external intervention in the markets. Further, as an output of the settlement process, PJM also adopted a shape for its demand curve that was less reliable than what it originally proposed as being most appropriate.[14] These criticisms are to demonstrate that even when the right design principles are understood and

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[13] It is interesting to note that while so many cogent observations regarding the benefits of a well designed demand curve were presented and supported in New England, much of what I perceive as problems in that market stem from the fact that ultimately no demand curve was adopted, and apparently "settled away".

[14] Also, as discussed below, despite the recognized benefits of a demand curve and fundamental reliance on a demand curve in RPM, tariff changes were implemented in 2011 that had the effect (intended or not) of creating once again a vertical demand curve with respect to annual capacity resources due to the improper capacity auction modeling of the reliability impacts of limited capacity resources such as demand response. *PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,066 (2011).

recognized by the sponsor and the Commission, intervening actions can undercut an appropriate solution.

13) These same considerations are manifest in the use of a forward procurement process. Just as the demand curve provides a feedback mechanism for quantity control and concurrently demonstrates elasticity of demand for capacity resources, a forward leading procurement mechanism provides for more transparency in forward pricing generally. This allows for elasticity in supply by providing sufficient time to build resources "into" the target delivery year and facilitates new entry at a price consistent with that paid to other resources.[15]

14) As to the *second* general principle, capacity markets must include locational and associated reliability constraints to create price signals that reflect the fact that capacity in certain congested areas potentially has greater value than capacity located elsewhere.[16] In general, the market also should be designed so that any capacity with attributes that provide for a differential reliability benefit (for example, beyond locational value the consideration of attributes such as quick start capability) will be recognized for those attributes and compensated accordingly. A corollary of this principle is the desire to minimize, if not eliminate, the need for out-of-market contracts, such as reliability must run (RMR) agreements.[17]

15) Thus, the notion of determining electrically cohesive areas wherein capacity is fungible, but areas between which capacity transfers are limited is key to assuring reliability. Probably the best reflection I have seen of this is the link between the Capacity Emergency Transfer Limit ("CETL")/Capacity Emergency Transfer Objective ("CETO") planning structure for the PJM regional transmission expansion plan (RTEP), local load deliverability, and the process for characterizing/adding new locational delivery areas within the RTO.[18]

16) Amazingly, despite the Commission's clear acceptance of the fundamental value of a locationally-based clearing concept, adherence to this principle also seems to be continually challenged. In the New York Independent System Operator, Inc. (NYISO) RTO, it took approximately six years to move from the recognition of the need for a

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[15] Similar to the design limitation regarding the lack of a demand curve in ISO-NE, NYISO choose a structure that did not include forward procurement, limiting the ability of the market to physically respond to auction price signals.

[16] *See, e.g., PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318 at P 76 (2007) ("Capacity market prices must be locational in order to be fully effective. Because of transmission constraints . . . separate capacity prices are necessary in separate locations in order to reflect the differences in costs and capacity needs among the locations."); *Devon Power LLC*, 103 FERC ¶ 61,082 at P 37 (2003) (directing ISO-NE to develop "a mechanism that implements location or deliverability requirements in the ICAP or resource adequacy market" so that capacity within zones "may be appropriately compensated for reliability").

[17] Shanker Testimony at 7.

[18] Generally, if PJM's RPM zonal constraints ,if fully displayed, would be close to a one-for-one match with underlying transmission planning requirements for load deliverability.

new capacity zone to its implementation. In ISO-NE, locational requirements have improved, but ISO-NE still does not have a fungible locational capacity product as each replacement transaction must be individually approved by ISO-NE from a reliability perspective despite the resource being located within the same zone.[19] In PJM, known locational constraints are actually removed from its auction formulation by virtue of its 115% CETL/CETO threshold for modeling locational delivery areas.[20]

17) All of these actions demonstrate, in my mind, a continuing corrosive interest in diluting locational price signals that is based on the perverse belief that a correct locational signal is somehow bad (translate "expensive") for market participants. This belief is rather perplexing as it is axiomatic that if a locational constraint binds, prices will indeed stay the same or increase on the "high" side of a constraint, but similarly, they will stay the same or decrease on the low side. Despite this obvious observation, it appears that there is great zeal in supporting/perpetuating the lack of accurate locational information in markets despite of the recognized problems created with respect to reliability.

18) *Third,* all competitive capacity resources within a given location should be compensated at the same price.[21] As the Commission stated with respect to PJM's RPM:

> In a competitive market, prices do not differ for new and old plants or for efficient and inefficient plants; commodity markets clear at prices based on location and timing of delivery, not the vintage of the production plants used to produce the commodity. Such competitive market mechanisms provide important economic advantages to electricity customers in comparison with cost-of-service regulation. . . . This market result benefits customers, because over time it results in an industry with more efficient sellers and lower prices.[22]

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[19] *See* ISO-NE Market Rule 1, Sections III.13.5 (f) and III.13.5.1.1.3 (b).

[20] PJM Open Access Transmission Tariff, Attachment DD § 5.10(a)(ii)A ("For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which . . . the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines."). *See also*, PJM Reliability Assurance Agreement, Schedule 10.1., Section B.

[21] *Id.*

[22] *See, e.g.*, *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 at P 141. *See also*, *Commonwealth Edison Co.*, 113 FERC ¶ 61,278 at P 43 (2005) (nondiscriminatory single-clearing price capacity auctions "ha[ve] the benefit of encouraging all sellers to place bids that reflect their actual marginal opportunity costs" and have been "found to produce just and reasonable rates for all the energy and ancillary service markets currently operated by the independent system operators and regional transmission organizations under our jurisdiction."), *order on reh'g*, 115 FERC ¶ 61,133 (2006); *Devon Power LLC*, 110 FERC ¶ 61,315 at P 45 (2005) (paying all "generators the same market-clearing price creates incentives to minimize costs, because a generator's cost reductions are retained by the generator and thus increase its profits" while paying "different amounts to different

The universally accepted "law of one price" for similarly-situated competitive units providing the same reliability service is a basic economic building block, and price discrimination among competitive supply is inefficient and in the long run will increase costs.[23] The suggestion in any manner that old versus new capacity has a differential reliability value is totally unfounded, and typically is only supported by desires to suppress market prices via discriminatory practices.

19) Here again, the Commission has been unambiguous in support of the single-clearing price market concept, but we continue to see erosion of this principle in market implementation. For example, in the PJM market design, while a must-offer obligation exists for existing generation, 2.5% of forecasted demand for the targeted delivery year is explicitly removed from the Base Residual Auction reliability requirements. This is a direct tool of price discrimination. For example, if the market were near balance and hypothetically needed just 1 MW of new entry, one would expect the new entry to set the clearing price for all capacity resources, existing and new. But this price signal would not be seen by the market at large under the existing PJM rules, as the Base Residual Auction (the first and primary auction) would only procure 97.5% of the reliability requirement, which would result in procurement of an amount less than that needed to "display" the required new entry. In this case, 97.5% of existing capacity resources (generation and demand response) will be paid a price that corresponds to the marginal clearing/mitigated carrying cost of the 97.5th percent most expensive resource. Only some portion of the remaining 2.5% of supply would ever "see" the correct clearing price consistent with the cost of new entry. This type of discrimination has been repeatedly identified and condemned by the PJM Independent Market Monitor, yet still persists.[24] This type of discrimination also will occur due to the existence of potential reliability backstops and/or RMR mechanisms in all of the markets, just as the Commission has recognized.[25] In other words, regardless of a clear recognition

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generators based on the level of compensation needed to keep the generator in operation would create a unit-specific cost-based system and undermine the advantages of a market for capacity."); *New York Indep. Sys. Operator, Inc.*, 110 FERC ¶ 61,244 at P 65 & n.76 ("Efficient pricing requires that suppliers receive the highest market value for their resources, independent of their bids [as] [t]his gives all sellers the proper incentive to offer their resources at the marginal cost of their highest valued use."), *order on reh'g*, 113 FERC ¶ 61,155 (2005); *New York Indep. Sys. Operator*, 103 FERC ¶ 61,201 at P 81 ("[A]ll capacity suppliers, regardless of the age of their resources, are entitled to the same treatment in the ICAP market. . . . The Commission does not see how [more expensive] generators could receive ICAP revenues that were fundamentally different from those paid to other generators. Moreover, those are the types of market signals the Commission would expect to encourage new generation additions.").

[23] *Blumenthal v. ISO New England Inc.*, 117 FERC ¶ 61,038 at P 83.

[24] Monitoring Analytics, LLC, Independent Market Monitor for PJM, State of the Market Report for PJM, January through June 2013 (Aug. 15, 2013), at 2, 5 ("[T]here are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions and the definition of DR which permits inferior products to substitute for capacity.").

[25] *Devon Power LLC*, 103 FERC ¶ 61,082 at P 29 (2003).

for the necessity of the elimination of price discrimination and violation of the fundamental law of one price, procedures to thwart this basic principle continue to exist and be supported in a piecemeal manner by the Commission.

20) *Fourth,* the exercise of market power by sellers and buyers must be mitigated to ensure that prices are neither artificially inflated nor artificially suppressed.[26] The exercise of market power by either side of the market is destructive for competition and long-term consumer welfare.[27]

21) Despite the unambiguous support of mitigation and recognition of the particularly destructive nature of buyer-side market power in capacity markets, we continue to see rules that erode any effective enforcement. Notwithstanding reasonably forceful and direct Commission language on this issue, the problem persists.[28] For example, in PJM, buyer mitigation only applies to combined cycle units, integrated gasification combined cycle units and combustion turbines, and large quantities of self-supply can be exempted.[29] In ISO-NE, it was estimated that as much as 3,300 MW of subsidized price suppressing generation was already in the market.[30] And in NYISO, it was only after significant protest, and then only prospectively, that mitigation was appropriately applied to a new entrant.[31]

It is against the backdrop of these key principles that I provide my short answers to the five specific questions posed for this panel in the August 23, 2013 Supplemental Notice.

Five Specific Questions:

22**) Question 1: How effective are the existing centralized capacity markets in assuring that resource adequacy needs are met at just and reasonable rates?**

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[26] *See, e.g.*, *New York Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211 at P 32 (2008) ("We find NYISO's proposal is a just and reasonable methodology for mitigating supplier market power, while maintaining revenue adequacy for suppliers . . . ."); *id.* at P 100 ("We accept NYISO's proposal for net buyer mitigation, with modifications, in order to prevent uneconomic entry that would reduce prices in the NYC capacity market below just and reasonable levels."); *Edison Mission Energy v. FERC*, 394 F.3d 964, 968-70 (D.C. Cir. 2005) ("[T]he Commission's contradiction of its prior rulings acknowledging the potential ill effects of forcing down prices absent structural market distortions [and yet still imposing seller market power mitigation) is the epitome of agency capriciousness."); *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 FERC ¶ 61,043 at P 78 (noting appellate court's "concerns with mitigation plans that mitigate workably competitive markets, suppress prices and deter market entry"), *order on reh'g*, 112 FERC ¶ 61,086 (2005).

[27] *See Devon Power LLC*, 115 FERC ¶ 61,340 at P 114.

[28] *New York Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211 at PP 106-110 (2008).

[29] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090 at P 19 (2013.)

[30] *ISO New England, Inc.*, 131 FERC ¶ 61,065 at P 65 (2010).

[31] *Astoria Generating Co., L.P. v. New York Indep. Sys. Operator, Inc.*, 139 FERC ¶ 61,244 at P 134 (2012).

Each of the three Eastern RTOs has significantly improved their market design *via* the addition of more viable capacity markets, but each has failed to honor fully the integrated requirements of the four basic principles I outlined above. The ultimate success of these markets, measured in terms of a lack of a need for external intervention, RMR-type agreements, and other out-of-market or back-up mechanisms, rests on removing the types of inconsistencies noted in the discussion above and putting in place non-discriminatory processes where transparent and competitive prices can result.

23) **Question 2: What modifications, if any, would you recommend be made to capacity markets in general or to specific capacity market design elements?**

Without going element by element, my general response would be that the markets will improve through closer adherence to the four principles described above. But some general recommendations are obvious: i) develop and always represent relevant locational constraints in any auction solution for a given capacity market; ii) eliminate any form of price discrimination (e.g., couple must-offer supply obligations with 100% demand estimates, do not allow preferences for new over existing resources, etc.); iii) create more uniformity of the capacity adequacy product in terms of basic eligibility (e.g. year-round availability) or alternatively have properly formulated constraints and clearing mechanisms to differentiate superior products (such as quick start) and constrain the amount and value of inferior products; iv) modify demand curves consistent with the explicit objective of the control of variance/volatility of price and most importantly, the elimination of the need for external intervention via backstops, RMR, or other out-of-market actions; and v) enhance forward procurement processes, particularly with respect to coordination with transmission planning and procurement.

24) **Question 3: Centralized capacity market design elements necessarily interact with each other and with the energy and ancillary services markets. Are there problems created by this interaction that should be addressed to improve the functioning of centralized capacity markets or energy markets?**

There are no problems created by these interactions, only problems created by a failure to recognize the interactions and adopt rules that appropriately integrate all related aspects of the market that are impacted by any change. This is not to say that appropriate solutions are simple and uncontroversial, but consistency is an over-riding consideration that often falls to the wayside as pieces of the problem are dealt with individually. We universally understand the need for consistent adaptation of requirements in interactive systems, except apparently when that obvious requirement clashes with the partisan objectives of market participants. This must be stopped.

25) PJM's incorrect modeling of Limited Demand Resources[32] within its RPM is a classic example of this lack of consistency, and the after-the-fact recognition that such inconsistency could/would ultimately lead to reliability problems. In this instance, PJM has properly recognized that Limited Demand Resources could not continue to be treated as the equivalent of annual capacity resources without at some point reaching saturation – that is, a point where there was no longer any material reliability benefit due to the limited nature of the demand response product. PJM also conducted reasonable studies to determine the maximum level of such saturation. But in adding two additional Demand Resource capacity products to the RPM market design (Annual Demand Resources and Extended Summer Demand Resources), PJM chose not to cap the quantity of identified inferior capacity products that could clear in the Base Residual Auction in a manner that was consistent with the results of their studies. Instead, PJM attempted to model the system in such a manner so that the Limited Demand Resources and Extended Summer Demand Resources could potentially clear in greater amounts (with per se no adequacy value), while setting a floor on the more valuable Generation Capacity Resources and Annual Demand Resources (in order to assure a minimum adequate reliability supply independent of the excess Limited Resources that were procured). In doing so, a modeling structure was selected that directly eliminated a basic design element (the demand curve) from functioning as intended (e.g. to control entry and exit) for approximately 90% of the market (*i.e.*, the Annual Demand Resource and Generation Capacity Resources) which are composed of existing and new generation and annual demand resources). Instead of working as originally intended, where the demand curve is the key control mechanism for the entire capacity market design, the current modeling mechanism acts as a vertical demand curve for those higher quality resources, and a downward sloping demand curve for the Limited Demand Resources, which have obligations to perform for only 60 hours out of the 8760 hours in a delivery year, and an acknowledged saturation point beyond which PJM has determined they have little if any value.

26) Though raised as an issue at the time, this deficiency was not addressed, and the implications of the impairment of the modeling mechanism on the market did not become manifest for several years. PJM is only now beginning to address the issue after many of the higher quality resources have decided to retire from service. My opinion is that the lack of the intended demand curve applying to annual resources, coupled with regulatory changes/expenses was a major contributing factor to the rapid deactivation of these resources. It remains to be seen if PJM's belated recognition of this problem will finally be translated into a proper representation of reliability/adequacy products within its auctions. What is clear is that a recognized inconsistency was purposefully added to the capacity market design, diminishing its overall effectiveness.

[32] All of the capitalized terms in this paragraph have the meanings ascribed to them in PJM's Reliability Assurance Agreement.

27) **Question 4: Regional capacity markets also interact with each other. What are the implications of regional differences in capacity market designs?**

Seams issues are inevitable. If a standard capacity construct is desired along with a uniform market for adequacy products, the easiest solution is to form a single RTO. Absent this, while there can and should be increased cooperation, parties have to recognize the implications of the different structures on their own individual markets, and not attempt to mandate their perceptions of what a capacity adequacy product should be on others that may have equally viable, but different market elements. I discussed this at some length in terms of contrasting the fundamental planning and probabilistic properties of PJM's reliability construct versus some of the criticisms raised by the Midcontinent Independent System Operator, Inc. (MISO) regarding inter-regional capacity transfers.[33] To some extent this issue appears to be exacerbated by the fact that few parties know all the underlying assumptions, properties and associated rules of all the markets, including their most immediate neighbors. Coordination can only occur when all of this knowledge is commonly understood by those attempting to improve seams related issues.

28) This in and of itself is not a criticism, but rather a simple recognition of the complexity that becomes a part of most organized market tariffs. In the absence of full reciprocal understanding, drawing the line between what is incompatible, and what is lack of coordination/cooperation is very difficult. Thus, a reasonable starting point is simply an educational step (some of which is underway with respect to at least PJM and MISO) to make sure basic assumptions are well understood, and potential interactions among these assumptions (e.g., deliverability, emergency transfer capability, tie benefits) are properly characterized and accounted for in any settlement of seams coordination.[34]

29) **Question 5: What is the impact on centralized capacity markets of transmission system upgrades and expansions? Can transmission planning be more effectively integrated with or accounted for in the design elements of centralized capacity markets?**

This question is a subset of the general concerns associated with Question 3. The most simple statement is that the transmission expansion process and capacity adequacy solutions interact, and should be coordinated via the capacity market and transmission planning mechanisms of the RTO to the extent possible.

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[33] *Capacity Deliverability Across the Midwest Indep. Transmission Sys. Operator, Inc., PJM Interconnection, L.L.C. Seam*, Statement of Dr. Roy J. Shanker Ph.D. on behalf of PJM Power Providers Group, filed Aug. 10, 2012, Docket No. AD12-16-000

[34] Other examples of these types of issues are differences in perception/treatment of firm transmission between the PJM and NYISO seam for capacity, as well as firmness of wheeling service through NYISO into ISO-NE.

30) Transmission drives fundamental factors in determining capacity deliverability and the associated definitions of capacity locational areas. Similarly, in many situations transmission can be a substitute for generation, and logically this should be allowed to be "seen" and to occur via the operation of the central capacity market. For example, to a limited extent the PJM market design allows for this type of competition between generation and transmission through the ability to bid Qualifying Transmission Upgrades into the capacity auction. But in general, because of the lead-time for transmission, there is a continual inherent bias that is continually exists in all of the markets to favor transmission solutions over generation or supply alternatives.

31) For example, in PJM, a shortage in CETL value (versus the CETO) between locational delivery areas triggers an automatic upgrade in the RTEP prior to any consideration/evaluation of or competition from a generation alternative. To some extent this bias is pre-ordained by jurisdictional limits, since the RTO can direct the construction of transmission *via* its reliability planning processes (at cost-of-service reimbursement), but has no similar authority regarding generation. This ability to direct the construction of transmission has resulted in a clear preference for transmission solutions, although that need not necessarily be the case. Longer lead times for capacity procurement auctions could allow for more head-to-head competition as well as the elimination of mandated builds for "economic" transmission.

32) This problem is not stagnant, but actually appears to be getting worse. For example, the bias towards transmission build-outs has even tilted so far that the PJM Markets and Reliability Committee recently approved a transmission upgrade criteria designed to add transmission when there is only an indirect indication (and no measure of benefit) that the transmission upgrade may impact whether or not a locational requirement binds in RPM.[35]

33) Obviously even from this cursory overview of the issues, it is clear that there is a continuing need for comprehensive evaluations, versus piecemeal, evaluations of capacity market design. Any specific solution must drive down to the necessary detailed level to address the consistency of objectives I have identified above.

I look forward to discussing these issues further with the Commissioners, Commission Staff, and my fellow panelists on September 25, 2013.

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[35] *See* PJM Markets and Reliability Committee August 26, 2013 Meeting Materials, *available at*: http://www.pjm.com/~/media/committees-groups/committees/mrc/20130829/20130829-item-03-rtep-easily-resolved-constraints-cstf-report.ashx.