UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Technical Conference re: Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators	)))))	**Docket No. AD13-7-000**

COMMENTS OF LEE DAVIS,
PRESIDENT OF NRG'S EAST REGION

My name is Lee Davis and I am President of NRG's East Region, which encompasses the PJM, NYISO and ISO-NE footprints. I appreciate the opportunity to participate on behalf of NRG and have provided some background comments on how NRG uses capacity market price signals to drive investment decisions, and then answer the questions specifically posed by the Commission below.

Background on NRG:

NRG Energy, Inc., owns approximately 46,000 MW of generation nationwide, including both conventional and renewable resources, over 2 million retail customers, and recently acquired several thousand MWs of demand response capability. NRG's generating fleet is split between parts of the country with a centralized capacity market (including PJM, NYISO, and ISO-NE), and areas of the country without a stable centralized structure for ensuring resource adequacy (including ERCOT, CAISO and MISO). My own responsibilities include overseeing operational and commercial affairs for our over 22,000 MW of assets in PJM, NYISO, and ISO-NE, serving more than 20 million customers.

Capacity Markets Drive Investment Decisions:

"Adapting to industry change" is the title of the next panel, but capacity markets have allowed NRG to successfully manage its generation fleet during an extremely challenging period in the industry. The Eastern capacity markets are critical to allowing companies like NRG to adapt to the steep decline in natural gas prices and corresponding decrease in energy revenues, changing federal and state environmental rules, and the fast-paced evolution of disruptive technologies. Without the centralized capacity markets, a substantial portion of NRG's oil- and gas-fueled fleet would not have sufficient revenues to remain in operation. These plants operate infrequently, but are critical to maintaining reliability at peak demand times and when the natural gas system experiences constraints. For example, during the summer 2013 heat wave almost 15,000 MW of NRG's units in PJM, NYISO and ISO-NE were online and generating power or committed to provide reserves. While all of the centralized capacity markets still have gaps and shortcomings that need to be addressed before these markets can be declared a success, they nonetheless are a critical component of every investment decision NRG makes in its East Region.

Elements of Successful Capacity Markets:

While there are economists and others on this panel better able to describe the theoretical underpinnings of "good" capacity markets, my experience is that there are six critical elements that provide the necessary price signals that drive NRG's desire to invest in a particular region:

a. Forward commitment period;

b. Sloped demand curve;

c. Locational price differentiation;

d. Comparability;

e. Mandatory centralized clearing; and

f. Appropriate and accurate mitigation rules (*i.e.*, rules that enable sellers to reflect all of the costs and risks of providing capacity, and protect against resources artificially suppressing price, such as the Minimum Offer Price Rule).

Each of the Eastern capacity markets has some, if not all, of these features. In contrast, markets such as MISO and California have virtually none of these features. Even the ISO-NE market, with its flawed design elements, still includes a forward commitment period and mandatory centralized clearing.

<u>Examples of Capacity Markets at Work:</u>

As someone in charge of directing NRG's investment dollars, I thought it would be helpful to the Commission to walk through how capacity markets actually drive NRG's investment decisions. The following are examples of how the capacity markets have enabled NRG to manage its fleet to the benefit of system reliability and consumers, by securing the least-cost sources of capacity:

- <u>*Avon Lake*: A Coal-to-Gas Conversion Success Story in the ATSI Zone</u>

NRG's Avon Lake facility, located in Avon Lake, Ohio, is a 753 MW generation facility (732 MW coal-fired) with its coal units originally put into service in 1949 and 1970. The coal-fired units at the plant were slated for retirement in 2015 by GenOn Energy, Inc., a predecessor of NRG, because of their inability to meet increasingly stringent environmental regulations. NRG is now in the process of enabling the coal units at the facility to operate on both natural gas and coal. NRG's decision to keep the facility on-line was largely based on the following factors:

- ✓ The (moderate) locational premium for capacity located in the ATSI zone, which includes the Cleveland area, provided NRG the necessary confidence to invest tens of millions of dollars in additional capital into the Avon Lake facility.

- ✓ The three-year forward commitment period will give NRG the necessary lead time to site, permit and construct a new natural gas lateral, as well as make the extensive changes to the facility's boilers to accommodate natural gas firing.

- ✓ The centralized auction structure provided a clear and transparent price signal that the cost of making this source of capacity available to the market represented the least-cost source of capacity to ratepayers.

- ✓ PJM's buyer-side market power protections, imperfect as they are,[1] gave us the confidence that uneconomic resources were unlikely to undercut competitive prices.

Each of these elements was critical to providing a level of price stability necessary to make this multi-year investment in this facility. It is hard to imagine how my counterparts in other parts of the country, without a forward price signal and some certainty of future revenues, would have the confidence to put this type of capital at risk. For example, making a comparable investment in California, with its bilateral market, would be very difficult to finance, as a generator would be required to seek recovery for the entirety of the capital expense in a single year. Incorporating the entirety of such an expense into a single year's bid risks pricing the resource out of the bilateral market. As a consequence, major maintenance expenses and incremental capital investments tend to be deferred, which simply increases ratepayer costs in the longer term.

- *Gilbert Unit 8*: Installation of Environmental Control Success Story in the JCPL Zone

NRG's Gilbert site hosts a 280 MW combined cycle facility located in Milford, New Jersey, within the JCPL Zone. Because of new environmental regulations in New Jersey, NRG was required to install environmental controls designed to limit the amount of NO_x produced by the facility. Installation of environmental controls at the facility was both expensive and technically challenging, and required a fundamental reconfiguration of the facility. However, after detailed economic and technical analysis, NRG was able to justify a significant investment in keeping some of the units at the Gilbert facility as viable resources for many of the same reasons that drove NRG to invest in retrofitting the Avon Lake facility, including:

[1] NRG has serious reservations about how PJM elected to implement its latest round of MOPR reforms. PJM's attempt to exempt new entrants from mitigation based on whether they "intend" to artificially suppress the market is contrary to basic economic theory, as well as invites manipulation. Instead, NRG supports objective, numeric analysis as to whether parties are bidding in a competitive manner, such as the MOPR rules that currently exist in NYISO and ISO-NE.

- ✓ The three-year forward commitment period gave NRG the necessary lead time to site, permit and construct required environmental controls.
- ✓ The centralized auction structure provided a clear and transparent price signal that the cost of making this source of capacity available to the market represented the least-cost source of capacity to ratepayers.
- ✓ The (modest) premium price available to resources in New Jersey.

- *Astoria Units 10 & 11*: Return to Service of Mothballed Units in New York City

The Astoria facility is comprised of 31 older combustion turbine units in New York City. NRG mothballed two of the units at the Astoria facility in 2012, when prices in New York City declined following the unmitigated entry of a contracted resource in Summer 2011, and persistent uncertainty regarding the application of buyer-side mitigation rules in the New York City market. During this period further investment to maintain the reliability of these units simply could not be justified. However, in the wake of several Commission orders upholding buyer-side market power mitigation rules, NRG was able to justify making the necessary investment to bring Astoria Unit 10 and Astoria Unit 11 back into the market. Again, the critical factors driving NRG's investment decision were:

- Locational premium for capacity within Zone J.
- Absence of market price suppression through the reinforcement of the buyer-side mitigation rules. In fact, the NYISO mitigation allowed truly merchant-build to enter the market, while economic projects were subject to a price floor.
- The presence of a sloped demand curve which provides a measure of price stability and dampens the boom-bust cycle caused by the lumpiness of entry and exit in the market.

Again, the capacity market in NYISO allowed NRG to reflect the actual price of making these resources available to the market, and its bid was accepted as the most cost effective method of allowing New York to meet its installed reserve margin needs.

- *Norwalk Harbor*: An Example of a Dysfunctional ISO-NE Market

The poor design of the ISO-NE Forward Capacity Market, or FCM, has directly led to NRG's decision to deactivate the Norwalk Harbor station. This oil-fired generation facility is the same type of resource that ISO-NE asserts it needs to reliably operate the system during periods of natural gas constraints. However, FCM revenues are not at all sufficient to justify either repowering this facility or allowing it to continue in the market. Here are the factors that NRG considered in deactivating the facility:

- ✓ Lack of a sloped demand curve means that prices in ISO-NE can be expected to approach near-zero levels, even when there is only a modest excess of capacity.
- ✓ The historical lack of buyer-side market power mitigation in ISO-NE resulted in over a thousand MWs of out-of-market capacity coming into the market that will continue to suppress prices into the foreseeable future.[2]
- ✓ Lack of real locational price differentiation in ISO-NE provides little hope of price recovery in the foreseeable future.
- ✓ Over-mitigation of offers from existing resources makes it extremely risky to bid capital investments into the ISO-NE market for fear that even real costs will be amortized under unrealistically long periods or disallowed altogether, leaving the resource with no ability to effectively price the full cost of its service, potentially forcing the premature retirement of otherwise economical resources.

While NRG sees severe problems with the ISO-NE market, we do not see ISO-NE's current suite of capacity market reforms, known as "Performance Incentive," as solving the problems underlying the ISO-NE market. Rather than attempting to address the material real-time energy market price formation problems with a badly misdirected set of capacity market changes, NRG would be far more willing to invest in New England if ISO-NE put into place a sloped demand curve and reformed its deeply flawed delist process. To date, however, ISO-NE does not appear interested in either of these common sense reforms.

[2] NRG won several of the contracts that created this problem. However, good market design requires that such out-of-market resources be mitigated appropriately.

- *Acquisition of Energy Curtailment Specialists*: Investment in Demand Response Driven by Capacity Market Price Signals

To end on a more positive note, capacity market revenues also continue to drive NRG's investment in alternatives to traditional generation. In August 2013, NRG purchased Energy Curtailment Specialists, or ECS, a leading supplier of demand-side management services. NRG was able to invest in demand response largely because of the revenues available to ECS from the capacity market. Indeed, ECS's portfolio is largely concentrated in PJM and New York – the two market areas with the most robust capacity market structures. ECS recently exited the ISO-NE market due to the overly complex capacity market rules and anemic market revenues, and has only modest participation in California and ERCOT, with no participation in MISO. NRG believes that the Commission's best method of incenting increased investment in demand response is to strengthen its capacity markets, particularly in areas of the country where capacity markets are moribund or non-existent.

Answers to the Questions Posed by the Commission:

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

The answer to the first part of this question is that the Eastern capacity markets have been fabulously successful in ensuring that PJM, NYISO, and ISO-NE are able to meet the reliability standard of one-day-in-ten-years Loss of Load Expectation. There is no question that capacity markets were critical to ensuring resource adequacy in these areas. Further, the Eastern markets have all weathered the impending retirement of 20+ GW of coal units in the 2015/2016 time frame with remarkable ease, while markets such as MISO without established capacity markets appear to be having more difficultly handling this transition.

The second part of the question asks whether these markets are returning just and reasonable rates, both for investors in capacity, as well as ratepayers. NRG and its predecessor companies have invested billions of dollars over the past ten years in power plants in PJM, NYISO and ISO-NE, largely on a merchant basis and largely based on the revenue opportunity that a capacity market provides. The Commission's initial vision for capacity markets was that a generator would have the opportunity to earn revenues from a combination of the energy, ancillary services and capacity markets that would average out, over time, to the cost of building and operating a new power plant. Under this competitive regime, every generator has the incentive to be the most efficient source of new capacity. Over the long term, the least expensive resource needed for reliability will recover its costs from the market, while less efficient competitors will be driven to become more cost effective. In order for this competitive dynamic to occur, the markets must reach "equilibrium" conditions.

To some extent, the vision has never materialized, as a variety of factors have prevented the markets from reaching equilibrium and functioning as intended, including:

- Surplus capacity in most of the markets since the beginning of the capacity markets, due in part to regulatory decisions to bring new capacity into the market, sometimes in spite of the market signals. The trend towards allowing market decisions to be driven by non-market actors is one of the greatest threats to the future success of capacity markets. Thus market participants need to have confidence in the Commission's Minimum Offer Price Rule and other similar rules.[3]
    - As examples, the Connecticut RFPs, the New York Power Authority contracts in New York, and the New Jersey LCAPP program all distort market signals and mask whether the markets are working.
- The influx of DR to the markets (which has a lot of similarity to the inrush of investment in combined cycle plants in the early days of restructuring) is also contributing to the surplus, and we probably have not reached an equilibrium level of DR yet.
- Sell-side mitigation policies that prohibit all resources from competing on the basis of long-run costs systematically inject volatility in price expectations and undermine confidence that the markets can produce prices that, on average and over time, reflect the long-run marginal cost of operating the marginal capacity resource.

[3] NRG actively bids on – and often wins – contracts directed by state regulators. Our participation in these programs does not diminish our concern that it is not the right approach from an overall market design approach.

NRG's view is that ratepayers have seen an enormous savings since the advent of capacity markets, compared to what ratepayers would have paid had they been paying full cost-of-service rates.

2. What modifications, if any, would you recommend be made to capacity markets in general or to specific capacity market design elements?

Every market should consider the features I mentioned above, including a sloping demand curve, strong buyer-side market power rules, a forward commitment period, and locational price differentiation. Additionally, the Commission must hold firm by avoiding erosion in the definition of the capacity product. Too often, market design "experts" want to mix and match capacity and energy market attributes. The Commission should avoid this tempting, but ultimately flawed, approach, and give the markets the chance to work. However, there are aspects of the existing markets that should be improved.

One important factor is the need for "comparability" between resources, including generation, demand response, and transmission solutions. Each of these resources has unique attributes which need to be recognized, but the Commission should encourage its ISOs and RTOs to establish robust competition to provide the least-cost set of resources that ensure reliability. While "comparability" is sometimes used as code for being anti-demand response, that is not what NRG believes. It is just as important that capacity markets evolve to encourage competition between generation and non-generation alternatives – including transmission solutions. Too often, the transmission expansion process puts into place transmission solutions that cost more than solving the same reliability problem with generation or demand response solutions. Yet the current market structure does not allow competition between transmission and non-transmission alternatives. (Note that while the NYISO has taken an important step towards allowing transmission and non-transmission alternatives to compete in its Attachment Y process, much work remains to be done.)

The ISO-NE market deserves special consideration. The FCM has evolved with a vertical demand curve, historically weak buyer-side market power protections, overly vigorous mitigation of sell offers, and no commercially feasible means of signaling the need for new investment in a facility. This combination of market design decisions is leading generators in ISO-NE to a position from which it will be difficult or impossible for many generation facilities to recover. The end result is likely to be procurement of more expensive new resources, the premature retirement of existing resources, and a loss of fuel diversity in the region. NRG sees this dynamic unfolding in real time within NRG's own fleet of approximately 3,000 MW in ISO-NE.

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?**

Energy price signals are an often overlooked input into capacity markets. Getting energy market prices "right" decreases the relative importance of capacity markets by reducing the market's reliance on capacity markets to make up the "missing money". While the experience of the energy-only market in ERCOT has shown that capacity markets are necessary to ensure an acceptable reliability margin, there is no question that ensuring that energy market prices accurately reflect actual supply-demand conditions would go a long way to improving overall market functioning, and also reduces the high-stakes litigation that currently plagues capacity market design decisions.

There is one additional point: capacity market revenues should be kept distinct from energy market performance or prices. ISO-NE's "Peak Energy Rent" deduction is an excellent example of what not to do. There, a generator's capacity revenues are reduced whenever ISO-NE has high real-time energy prices. This mechanism unfairly and inappropriately deducts from all suppliers' capacity revenues, while very few market suppliers have access to the actual real-time revenues, since typically 85-90% of the market clears in the day-ahead. This and other mechanisms that would adjust capacity revenues depending on outcomes in the energy or ancillary service markets should be eliminated or avoided. The structure should instead rely on capacity sellers to make their own estimates of energy and ancillary revenues when they formulate their capacity market price offers.

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

The recent influx of capacity resources from MISO into PJM shows what happens when a robust capacity market interconnects directly into a market that has not been directed by the Commission to further develop to a robust standard. The artificial price disparity between the $1.05/MW-Day price returned by the MISO capacity market for the 2013/2014 delivery year and the PJM RTO price of $27.73/MW-Day for the same delivery period tells the entire story. In a "flight to quality," capacity is rushing out of MISO, despite the apparent need for additional resources in MISO in the 2016 – 2018 timeframe. One market's strength cannot support a neighboring market's weakness, without beginning to weaken itself. The ramifications are that there may be a loss of properly-located resources needed for reliability in PJM, when the inevitable snap-back occurs to keep the lights on in the MISO region. This seams issue, caused by the lack of a viable market in MISO, should be a primary concern for the RTOs and must be addressed by the Commission.

There has been quite a bit of discussion in the last six months about reforming the PJM process for qualifying external resources, which is only treating the symptoms of the disease and not the cause. Only when the Commission installs a robust market in MISO will the exodus of resources – including those needed for reliability in MISO – cease. This includes some of NRG's own resources that procure firm transmission service through MISO in order to participate in RPM. It is not at all clear that this is a societal benefit; but it is what the market price signals across the seam are suggesting is the most economic decision.

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 is a critical and often overlooked point. Other than in New York, transmission planning and decisions to build transmission are disconnected from the capacity market in any practical sense. Ideally, generation and transmission should compete directly, on an economic basis, to resolve capacity or other deliverability constraints. We often see transmission projects selected as part of the regional transmission planning process, even when there are less expensive generation solutions available. At a minimum, proposed transmission should be evaluated against generation options in capacity auctions to determine the most cost-effective way to reduce congestion. NRG would fully support efforts by the Commission to promote competition between transmission and non-transmission solutions.[4]

Respectfully submitted,

/s/ Lee Davis
Lee Davis

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[4] NRG discussed several specific ideas for promoting this type of competition in its filing in AD09-8-000 (filed Nov. 23, 2009).

Biography of Lee Davis

Lee Davis serves as Executive Vice President and Regional President, East, overseeing commercial and operating activities and business development for NRG's largest region by generating capacity. With almost 22,000 megawatts of generating assets in the region, he is responsible for leading efforts to maximize the value of existing units, repower generating sites with more efficient units, reduce emissions from the region's fossil fueled plants and build new clean energy resources. Mr. Davis joined NRG in 2006 as Vice President, New York Development and took on the expanded role of Vice President, Northeast Business Development in January 2010. Prior to his current position at NRG, he took on various roles as a Vice President for Mirant Corp. and as Vice President of Strategic Origination at Calpine Corp. Mr. Davis has a master's of business administration from Emory University and a bachelor's degree from the Georgia Institute of Technology.