May 8, 2014

The Honorable Senator Mary J. Landrieu
The Honorable Senator Lisa Murkowski
The Honorable Senator Maria Cantwell
The Honorable Senator John Barrasso
United States Senate
Committee on Energy and Natural Resources
304 Dirksen Senate Building
Washington, DC 20510-6150

Dear Chairman Landrieu, Ranking Member Murkowski, Senator Cantwell, and Senator Barrasso:

PJM appreciates the Committee’s continued focus on the reliability and security of the U.S. electric grid and the opportunity for Michael J. Kormos to testify during the April 10, 2014 hearing. PJM looks forward to further conversations, and would like to offer responses to the questions posed to us in your letter dated April 24, 2014.

Please find responses to the Committee’s specific questions below:

Craig A. Glazer
Vice President – Federal Government Policy
PJM Interconnection
From Senator Cantwell

Question 1

A shortage of transformers has been identified as a resiliency problem for the grid. What options should Congress consider to promote the manufacture of transformers?

PJM Response:
As early as 2006, PJM proactively began analyzing and taking action on the need to ensure the availability of an adequate supply of spare critical transformers. Specifically, PJM undertook a detailed probabilistic risk analysis of the existing fleet of critical transformers in use throughout the PJM 13-state footprint. That analysis looked at both the reliability impacts as well as the price impact to customers of the failure of specific transformers in order to analyze, from a cost/benefit viewpoint, where best to invest ratepayer dollars to procure spare transformers. Moreover, in working with its transmission owners, PJM utilized that analysis to develop standardized specifications for the procurement of transformers and formally, through PJM Board action, ordered the procurement of a number of spare transformers at key locations throughout its footprint consistent with PJM’s cost/benefit analysis. Based on this analysis, seven spare transformers have been purchased, in addition to the existing number of spares located throughout the PJM system. Also based on this PJM analysis, Transmission Owners replaced 103 transformers identified as being a risk based on the age of the transformer. Currently, PJM has spare transformers at 38 of 49 substations (note: Those substations that do not have spares either do not have adequate risk to justify placing a spare transformer at the location, or have sharing arrangements with another location).

The type of focused analysis that PJM undertook could be helpful to promote the manufacture of transformers and allow for more standardization than currently exists in transformer design and utilization. Each substation and each transmission owner will need to adapt transformers to their individual systems but the more standardization that can occur over a larger regional footprint, the more incentives will exist to promote additional manufacture of transformers as some of the inefficiencies associated with the need for individualized design and construction can be removed. Nevertheless, transformers will never become a true “shelf product” and the demand for transformers will be uniquely affected by grid topology, the level of demand for electricity and the overall age of the existing fleet. Transformers are utilized in electricity grids throughout the world. Factors such as grid topology, the demand for electricity and the age of the existing fleet of transformers vary widely around the globe making the pace of manufacturing as well as the location of manufacturers of transformers uniquely affected by worldwide demand rather than just US demand.

At FERC’s direction, the industry is undertaking an intensive effort at addressing security issues around critical substations. Moreover, federal as well as private dollars have been pledged toward efforts to “harden” the grid as a result of extreme weather events such as Hurricane Sandy. Although we do not believe that additional legal authority or federal funding is necessarily needed at this time, a focus on promoting the type of holistic analysis such as what PJM has undertaken in analyzing both reliability and market impacts from transformer failure could be helpful in determining the right level of spare transformers to have available for use. PJM stands ready to participate in industry discussions on utilizing the kind of regional analysis that PJM has already taken or exploring alternatives to ensure the right mix of this critical component of the electric grid going forward.
**Question 2**

Please clarify the 22 percent loss of generation capacity during the polar vortex. How much of this lost generation was attributable to coal, natural gas, and nuclear power, separately? I would like to better understand the extent to which coal generation was, or was not, more reliable than other kinds of base load power generation.

**PJM Response:**

During the Polar Vortex the 22 percent loss of generation capacity (forced outages) totaled 40,200 MW. These unavailable megawatts were due to either the entire generator being unavailable or a limitation of megawatts the generator can supply to the system. The primary fuel types that were unavailable during the peak, comprising this forced outage amount, were natural gas, coal, and nuclear. Of the total forced outage amount, 19,000 MW (47 percent) were natural gas, 13,700 MW (34 percent) were coal, and 1,400 MW (3 percent) were nuclear (the remaining 6,100 MW was a combination of other fuel types such as oil, wind, hydro, waste, etc.).

Forced outages experienced by coal units during the Polar Vortex were primarily due to multiple effects of the extreme cold weather on various components of coal handling and processing facilities. Frozen coal or wet coal, frozen limestone, frozen condensate lines, frozen fly ash transfer equipment, cooling tower basin freezing, and freezing of injection water systems for emissions control equipment were among the numerous causes of coal unit forced outages.

Regarding overall reliability of coal generation compared to other kinds of base load generation, the magnitude of gas related forced outages during the Polar Vortex exceeded that of coal related forced outages, but the coal related forced outages comprised approximately one-third of the overall forced outage total.

PJM analyzed the performance of approximately 14000 MW of generation pending retirement during the Polar Vortex peak. PJM determined that the generators pending retirement were producing at a level of approximately 52% of their capability.

**From Ranking Member Murkowski**

**Question 1**

What winter, summer, or shoulder period modeling, if any, has PJM done in the past 10 years?

**PJM Response:**

PJM models a range of seasons, including winter, summer and shoulder in a variety of timelines from the present time through a 15 year planning horizon. The two major timeframes are the operating and planning horizons. The modeling in the operating horizon encompasses the present day up to one year into the future. The planning horizon models the longer term anticipated system from one year through the 15 year planning horizon.

In the operating horizon, PJM completes summer and winter pre-seasonal studies that are conducted by the PJM Operations Analysis Task Force (OATF). In addition, near-term studies are performed on models that reflect the anticipated next day configuration and demand in advance of every operating day. These operating analyses evaluate the system considering existing transmission system topology and resources, planned transmission outages, planned generation outages, forced transmission outages, and forced topology outages.
In the planning horizon, PJM conducts extensive modeling and assessment of the system as part of the Regional Transmission Expansion Plan (RTEP). PJM completes exhaustive studies of the transmission system throughout a 15-year planning horizon as part of the RTEP. These studies include analyses of the system at various load levels and consider generation outages and conditions consistent with the period under study. Following is a link to the recent studies that have been completed pursuant to the RTEP.

**Regional Transmission Expansion Plan (RTEP) Documentation**


In addition to the RTEP studies, PJM also completes seasonal assessments of the transmission system as part of the OATF. Links to these studies can be found at the following locations:

**2014 OATF Summer Study Summary**

http://www.pjm.com/~media/committees-groups/committees/oc/20140506/20140506-item-08-oc-presentation-2014-summer-oatf.ashx

**2013-14 OATF Winter Study Summary**

http://www.pjm.com/~media/committees-groups/committees/oc/20131209/20131209-item-08-oc-pesentation-2013-14-winter-oatf.ashx

In addition to the modeling requirements for PJM operating and planning activities, PJM also participates in the development of modeling by the Multiregional Modeling Working Group (MMWG), a group responsible for developing a library of solved power flow models and associated dynamics simulation models of the Eastern Interconnection. The models are developed for use by the Regional Reliability Organizations and their member systems in planning future performance and evaluating current operating conditions of the interconnected Bulk Electric System. The annual MMWG case builds typically include fourteen (14) cases that include a variety of future system model years and also a variety of system demands including light load, spring, summer, summer shoulder, fall and winter. This process has existed for more than 10 years and PJM has participated during that time. PJM annually uses several of the MMWG models for the Regional Transmission Expansion Planning (RTEP) assessment.

**Question 2**

If modeling has been done, how is it used and is it distributed beyond PJM?

**PJM Response:**

PJM’s models that are used for the RTEP assessment are available on www.pjm.com pursuant to CEII handling procedures.

http://pjm.com/planning/rtep-development/powerflow-cases.aspx

In addition, MMWG modeling is available directly from the MMWG pursuant to CEII and modeling release procedures.


PJM is also very transparent in sharing the results of the assessments that are performed on the various models. The PJM RTEP is the transmission enhancement plan that results from analysis of the future models. This plan is reviewed extensively with PJM.
stakeholders. In addition, the MMWG models are used by Transmission Owners, Generation Developers, Load Developers, Transmission Planners, Planning Coordinators, economists, et al. for thousands of annual studies of the Eastern Interconnection to examine system reliability.

Studies are also shared and reviewed with neighboring balancing authorities including Midcontinent ISO, New York ISO, TVA, Duke Carolinas and VACAR through a variety of forums. The study forums include the Inter-Regional Stakeholder Advisory Committee (IPSAC) where targeted studies coordinated by PJM and neighboring entities. Additionally, PJM also participates in a variety of studies coordinated by our NERC Regional Reliability Entities. These studies include analysis coordinated with the entities in both the ReliabilityFirst (RFC) and the SouthEast Electric Reliability Council (SERC) footprints.

Question 3

In your written testimony, you state that “the reliability cushion we [PJM] previously enjoyed with the large fleet of coal-fired generation has substantially diminished.” You further note that demand response resources are only available to the RTO when you are in “pre-emergency” conditions as you define the term. In fact, you say “we will potentially have to run the system closer to its limit than we have previously in order to be able to call on demand response resources.” Please elaborate. Does this concern you?

PJM Response:

PJM’s emergency procedures call for PJM to deploy long and short lead time demand response resources during hours when the system is actually in emergency condition. This action is taken by PJM to deploy demand response resources in order to avoid PJM invoking further emergency procedures. Calling on these demand response resources to be available to reduce their demand is one of the earliest stages in PJM’s multi-layered emergency procedures. To date, demand response resources have performed well in response to PJM’s call in these circumstances. It should also be noted that within the requirements of the PJM tariff and their obligations as capacity resources, DR capacity resources face substantial penalties should they fail to reduce when called upon by PJM to do so.

Nevertheless while allowed and encouraged, demand response resources have not been willing to also participate in PJM’s energy market through the submission of an economic bid that would allow the load reducing benefits to be available earlier to PJM and prior to PJM having to invoke emergency procedures to reach these resources. In addition, demand response resources face a much higher bid cap (presently set at $1,800/MWh) as compared to generation which must submit a bid in the energy market at $1,000/MWh. The issue as to whether demand response should be required to submit a bid in the energy market is presently pending before the Federal Energy Regulatory Commission (FERC).

The fact that PJM cannot reach demand response resources until PJM has moved into emergency conditions is the basis for our statement in Mr. Kormos’ testimony that “we will potentially have to run the system closer to its limit than we have previously in order to be able to call on demand response resources.” We have recently tried to somewhat mitigate this concern by proposing to FERC a “pre-emergency” category that allows PJM to call upon demand response resources immediately prior to entering emergency conditions and by proposing to shorten some of the notification periods prior to our being able to call upon demand response resources. That proposal is also pending before the FERC and was not in effect during the Polar Vortex.

Nevertheless, because of the advent of demand response resources and their growing role in serving as capacity resources in PJM, we will be required to run the system closer to emergency conditions than we have before. Moreover, with the loss of a
sizable portion of the coal fleet, the resource mix, although more diverse than it has been before, is made up of a portfolio that potentially has less flexibility than existed previously.

This changing nature of the resources is certainly a concern. It does not cause reliability issues for PJM—we procure reserves above our installed reserve margin to address these very type of contingencies but does increase complexities for PJM system operations and will result in greater price volatility for customers. PJM has been proactively addressing these challenges through a variety of filings before FERC incentivizing the clearing of year-round demand response products and more flexibility in PJM operations’ ability to call upon and dispatch these demand response resources. FERC’s rulings have so far been very helpful in addressing PJM’s concerns. Additional issues such as whether demand response should have a “must offer” energy bid as well as some of our operational reforms, are pending before the Commission in active proceedings.

**Question 4**

Your written testimony notes that during the Polar Vortex, the “system was indeed very tight, [but] we were never—as some accounts have portrayed—700 megawatts away from rolling blackouts.” How close was the PJM system to a rolling blackout? You further noted that PJM’s next step would have been to implement a small voltage reduction. Is it typical to implement voltage reductions to manage the system or is that something the grid operators would prefer to avoid if possible?

**PJM Response:**

While the system’s Synchronized Reserves (reserves that are supplied to the system from resources that are synchronized/connected to the grid and able to load within 10 minutes) fell to a low of approximately 500 MW for a brief 5 minute period of time and averaged around 700 MW for that hour, they are not the only reserves PJM has that can be deploy prior to requiring rolling blackout. PJM had an additional 1,167 MW of primary reserves (reserves available in 10 minutes but not synchronized) for a total of 1,667 – 1,997 MW ten minute reserves in the lowest hour. As well PJM could have deployed a 5 percent voltage reduction to further reduce load and create reserves as we had done the previous night and is a specific step in our emergency procedures. PJM would expect about 1,100-2,000 MW of relief from this step. PJM also has reserve sharing agreements with our neighbors that could have been called upon if needed. PJM’s agreement with NPCC allows up to 50 percent of the contingent loss to be requested and PJM’s VACAR agreement allows up to 1,263 MW to be requested. All or part of all available resources would have been deployed prior to requesting rolling blackouts. We would estimate we had between 2,500-4,000 MW of reserves remaining.

While PJM always attempts to avoid emergency procedures when possible, they are designed and expected to be deployed in extreme situations such as the one we faced during the polar vortex.

**Question 5**

Do you agree with GAO that NERC and FERC should have a formal and documented role in EPA’s rulemaking process when EPA is developing regulations that impact grid stability?

**PJM Response:**

PJM believes that reliability issues must be considered in the context of EPA’s rulemaking process. Reliability analyses should be conducted during the formulation of EPA’s policy proposals. In addition, PJM believes that appropriate “safety valves” be built into
final EPA rules so that there is a means to address reliability impacts that may arise from a specific rule’s implementation. It is for this reason that the ISO/RTO Council proposed a “Reliability Safety Valve” which was eventually incorporated into the EPA Mercury and Air Toxics rule. The ISO/RTO Council has proposed a similar “Reliability Safety Valve” for incorporation into EPA’s impending greenhouse gas rule.

PJM believes that the entities responsible for system operations as well as planning are in the best position to conduct the majority of “on the ground” reliability analyses of the impacts of various proposals. Nevertheless, both NERC and FERC can play a valuable role in this process and as a result, FERC and NERC should have the formal documented role in any EPA rulemaking process with RTOs/ISOs and other system operators providing input to all of these entities, including EPA. NERC provides a national view of bulk electric system reliability and can provide an independent verification of the reliability analysis undertaken by system operators. Moreover, there remains an important question of legal authority to address reliability. Congress has given that role to FERC and although there seems to be some concern as to EPA’s ability to address these issues under the Clean Air Act, there is no question that Congress sought federal regulatory oversight of bulk power reliability by assigning that task to FERC through the Energy Policy Act of 2005. Accordingly, both FERC and NERC as well as the RTOs/ISOs have an important role in this process. The “formal and documented” role should be limited to those entities that Congress has specifically recognized in this area—namely FERC and NERC (the latter acting as the Energy Reliability Organization appointed by FERC pursuant to EPACT 2005). The RTO/ISO role and other system operator roles’ should not necessarily be “hard-wired” into the rule but clearly are an integral input that should be sought by EPA, FERC and NERC through the rulemaking process.

**Question 6**

Do you believe current market prices for energy and capacity are sufficient to attract investors to invest their capital in a new coal facility even though EPA standards would require the use of CCS technology that is not commercially viable?

**PJM Response:**

The independent PJM Market Monitor has determined that over the last several years, the overall revenues being received from the various PJM markets have been less than needed to recover the overall fixed and operating costs of a new coal plant. Specifically in his 2013 State of the Market Report, the IMM stated:

> In 2013, a new CP (“coal plant”) would not have received sufficient net revenue to cover levelized fixed costs in any zone. The results for CPs are relatively uniform. A new CP would not have received sufficient net revenue to cover more than 30 percent of levelized fixed costs in any zone. However, the results for coal plants in 2013 are better than they were in 2012 based on higher energy market net revenues in all but one zone and higher capacity market revenues in ten zones. These are the same ten eastern zones that increased the net revenue results for both CTs and CCs. All but two zones showed increases in the coverage of fixed costs by CPs in 2013.

PJM’s markets are designed to be resource-neutral. As a result, our capacity market clears resources at the cost of new entry of the most efficient new technology available to supply the needed MW’s—presently represented as a gas combined cycle unit. But the capacity markets only make up approximately 30 percent on average of the total revenue stream for a given generator. Coal units receive revenues above their marginal costs in many hours in the PJM energy market which clears in many peak hours at the cost of producing energy from natural gas which often is more expensive than production of energy from coal. As a result, the total revenue picture from the combination of the PJM markets is examined by the PJM Market Monitor.
PJM has not undertaken a specific analysis, but given the observations of the independent market monitor as to the net revenue position of new coal plants without CCS, we believe that a requirement for mandatory CCS technology would further exacerbate the strain on the viability of new coal technology from being developed.

**From Senator Barrasso**

**Question 1**

You explain that EPA’s regulations will cause utilities to rely to a greater degree on demand response programs. Through demand response programs, utilities compensate customers who voluntarily agree to curtail their use of electricity during emergencies. You suggest that demand response programs will help utilities make up for the loss of coal-fired electric generation resulting from EPA’s regulations.

Earlier this week, Tony Alexander, President and CEO of First Energy, explained that: “Many businesses are now considering whether they can continue to interrupt their ability to manufacture the product they sell in order to accommodate the changes being made in the electric system.”

He went on to say that: “If [these businesses] change their minds, all customers could be left with inadequate power supplies.”

Do you believe Mr. Alexander has correctly characterized what is at risk with utilities relying on demand response programs?

**PJM Response:**

PJM believes that Mr. Alexander’s statement has validity but does not represent the entirety of the picture. For one, a decision of a business customer to simply renege on its prior demand response forward commitment to the PJM market is not without substantial cost. That business, acting through its curtailment service provider, is required to either replace its promised reductions with another capacity resource or face substantial penalties for not being available to PJM despite its prior commitment. Thus, the problem of industrial customers simply “changing their minds” in the short term is not without substantial cost that works to disincent such sudden reversals.

Moreover, every year PJM procures megawatts above its forecasted reserve margin (which itself is designed to account for the unavailability of specific resources at the time of the system peak). PJM’s required reserve margin currently is 16.2 percent; however, PJM’s forward capacity auction has procured up to a 21.1 percent reserve margin on a 3-year forward basis. PJM will continue to procure these additional supplies in order to address the type of concern raised by Mr. Alexander.

Beyond the three year forward commitment period, PJM believes that businesses could stop providing demand response if the cost of producing the business’ product could exceed the cost of curtailing that production when called upon by PJM. From a reliability perspective, PJM’s market structure is designed to attract new resources that would substitute for this loss of demand response resources should there be an exit from the market. In essence, capacity prices would rise should there be an exit of the market by demand response resources which would then incent the development of new short term resources to substitute for those exiting resources. Moreover, as gas generation can generally be developed in a relatively short time period (particularly in the PJM region which sits on top of the substantial Marcellus and Utica shale supplies), the market should work to produce substitute resources. Nevertheless, PJM has the authority to procure additional resources should the market, for some reason, not produce the amount of megawatts needed to meet our projected peak demand.