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*Advocating the **power** of competition*
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October 9, 2014

Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

RE: EPSA Comments for Department of Energy Quadrennial Energy Review

The Electric Power Supply Association respectfully submits these overview comments in response to the U.S. Department of Energy request for comments on the Quadrennial Energy Review due October 10, 2014.

The Electric Power Supply Association (EPSA) is the national trade association for leading competitive wholesale electricity suppliers, including power generators and marketers. EPSA members include both independent power producers and the wholesale supply businesses of utility holding companies.

EPSA members supply electricity nationwide with an emphasis on the two-thirds of the country located within a regional transmission organization or independent system operator (organized markets). EPSA members and other competitive suppliers account for 40 percent of the installed electric generating capacity in the United States. These suppliers are the primary sources of electricity for most of Maine to Virginia, across to Illinois, and in Texas and California.

EPSA members individually and collectively operate a fuel diverse and technologically innovative fleet of power plants. EPSA members are the largest or among the largest operators of natural gas, nuclear, geothermal and solar power plants, own substantial lower-emission coal assets, and are major developers of wind and hydro resources.

EPSA's competitive electricity companies are implementing the vision that that Congress sought in the Energy Policy Act of 1992. The Department of Energy also had an instrumental role in shaping this important piece of legislation. Competitive suppliers do not have a cost-based regulatory recovery mechanism as is the case with traditional cost-of-service utilities with monopoly service territories. Competitive suppliers must earn market revenues within detailed rules set by the Federal Energy Regulatory Commission.

Currently, the electricity industry is facing a number of challenges and headwinds. Low load growth has become the new normal and natural gas prices are resulting in lower energy market revenues. There is an increased amount of resources participating in wholesale markets with out of market revenues. In addition, the increased role for variable and distributed resources continues to impact revenues and costs of suppliers for other resources needed for reliability. Finally, the industry faces the evolving effects of new technologies whose impacts and timing remain unknown variables.

With the aforementioned in mind, EPSA fully understands that the scope of the first phase of the Department of Energy's Quadrennial Energy Review (QER) will focus on transmission, storage and distribution infrastructure as noted in the inaugural January 2014 meeting at the Department of Energy. Notwithstanding this original scope, EPSA comments representing competitive electric suppliers are relevant in the first phase of the QER given the fact that, broadly speaking, without generators supplying the electricity to the grid there would exist only uncharged wires and idle infrastructure; and more specifically, several issues of specific interest to competitive electricity generators were raised at various Department of Energy forums held to receive input on the QER.

Competitive Electricity Enhances Flexibility, Adaptability and Innovation.

The competitive business model shifts the considerable risks of power plant development and operation from consumers to investors. This means that as the energy resource landscape continues to shift, often in dramatic ways, the considerable risks associated with how much supply and of what type should meet what amount of expected demand through various means as technologies advance (supply and demand resources) are not borne by consumers as they are under the traditional utility regulatory model.

Wholesale Electric Market Reforms Are Urgently Needed to Support Generation Infrastructure.

The QER forums held this past year have focused on the need for infrastructure to ensure reliability of the electric grid among other topics. EPSA strongly supports competitive wholesale power markets, which provide significant consumer benefits but require well-functioning updated market designs and tariffs properly implemented through grid operator practices to send proper price signals for market-based infrastructure investment as to power generation. To that end, investor risks should be accompanied by the opportunity to earn revenues sufficient to recover fixed and variable costs plus a reasonable return on invested capital; there are no guarantees in a competitive market, but nor should there be unnecessary barriers created by market-distorting actions. One example of market distorting actions with negative consequences to consumers is occurring in New England and New York where some states have considered pursuing preferential long term power contracts for provincially-owned and foreign subsidized large-scale hydropower. This ill-conceived pursuit was raised at the Department of Energy's QER Forum on April 21, 2014 in Hartford, Connecticut. If undertaken, it would unfairly undercut regional investments made on a competitive basis and cause market distortions over time.

EPSA has submitted detailed comments to the Federal Energy Regulatory Commission (FERC) outlining why our market reform proposals are urgent given the aforementioned challenges facing the electricity industry. These include *Organized Wholesale Markets Require Meaningful Reforms In Light Of Serious Challenge;* a paper *The Polar Vortex: Implications for Improving the Efficiency of Wholesale Electricity Spot Market Pricing A. Joseph Cavicchi, Compass Lexecon, on behalf of EPSA,* and *Post-Conference Comments of the Electric Power Supply Association Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators.*[1] EPSA has attached these papers to the comments herein. In sum, EPSA believes FERC must undertake market reforms in the following areas:

1. Energy Market and Ancillary Services Price Formation
2. Capacity Market and Resource Adequacy Rules
3. Out of Market Entry and Uneconomic Supply
4. Proper Role for Demand Response
5. Transmission and Seams

EPSA welcomes and supports FERC's leadership and action to achieve improvements to market design, tariff rules and grid operator practices, and will continue to work with the Commission and the regional markets to develop and implement solutions on a timely basis. The Commission's procedural options to

[1] EPSA POST-CONFERENCE COMMENTS OF THE ELECTRIC POWER SUPPLY ASSOCIATION Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators. May 14, 2014 Federal Energy Regulatory Commission Docket No. AD14-8-000 including Attachments A: (*Organized Wholesale Markets Require Meaningful Reforms In Light Of Serious Challenges* Presentation by: Electric Power Supply Association January 2014) Attachment B: (*The Polar Vortex: Implications for Improving the Efficiency of Wholesale Electricity Spot Market Pricing A. Joseph Cavicchi, Compass Lexecon, on behalf of EPSA)*

accelerate timely market improvements are many, and all steps should be employed as necessary and appropriate (e.g. individual ISO/RTO cases on specific issues, broadly applicable best practices and policy statements with mechanisms for ISO/RTO accountability, rulemakings, and general oversight). In particular, EPSA has encouraged the Commission to continue to act in individual RTO dockets on timely market improvements consistent with these comments and the sound market principles on which they are based.

Electric and Gas Coordination is Essential to EPSA Members as Large Consumers of Natural Gas.

EPSA commends the Department of Energy for holding a Quadrennial Energy Review forum in Denver, Colorado on July 28, 2014 on Gas-Electricity Interdependencies.

EPSA members, as large consumers of natural gas, have a major stake in robust natural gas supplies and a reliable natural gas delivery network. EPSA members with natural gas assets have as much interest as anyone in making sure natural gas supplies can be delivered to their power plants when needed to generate electricity. This is so because under the competitive business model, power plants do not earn their primary source of revenues (sales of electricity) unless the power plants run, which requires reliable access to competitively-priced natural gas.

There are many ways by which gas-fired power plants procure fuel to reliably generate electricity day in and day out. One way is to purchase firm transmission on an interstate pipeline, but it is not the only way and it is not always the most cost-effective or operationally-feasible. Furthermore, some plants are not served directly by interstate pipelines but instead get fuel from local natural gas distribution companies. Thus, firm transportation on interstate pipelines is and should remain a business option for power plants, not something to be mandated.

The timing and volume of natural gas demand to generate electricity is highly uncertain and variable; natural gas for power generation is not consumed ratably or predictably. Demand for electricity changes by the second, hour, day, month, season, and year, as well as across decades. In addition, natural gas power plants are major but not the only sources of electricity in a given state or region; thus they compete with other fuels.
To supply consumers with the least-cost resource mix, grid operators use least cost economic dispatch to decide which plants operate to meet demand. Power

plants are generally dispatched in short time increments on a least cost basis within transmission constraints. These plants receive revenues for the sale of electricity from the day-ahead and real-time energy markets administered by RTOs/ISOs. Many of these regions serve states that elected to provide their consumers with the benefits of customer choice through retail competition based largely on annual contracts. Thus, there are timing and quantity mismatches between the nature of electricity, the design of wholesale and retail electricity markets, and the desire of at least some pipelines to push the risk of building new pipeline capacity on which they would receive a regulated rate of return on to power generators and their customers via requiring multi-decade firm natural gas transportation contracts.

To best serve consumers, power plants have many options to tailor how and when they obtain fuel in ways that reduce the cost of generating electricity reliably. Power plants can negotiate packaged services from producers and marketers that include firm or interruptible gas transportation that the producer or marketer has contracted for with an interstate pipeline. Power plants can enter into interruptible pipeline contracts directly or they can use the secondary release natural gas transportation market which is a win-win for electricity and natural gas consumers. In this manner, a holder of firm gas transportation that has capacity it will not be using (such as a local natural gas distribution company) can re-sell it to a power plant. This offsets the local gas utility's costs and uses the gas delivery system more efficiently.
Thankfully, these various commercial arrangements work exceptionally well virtually all of the time even under stressful conditions, such as during the Polar Vortex the country experienced in the winter of 2014. EPSA and its member companies are active in all the various FERC and regional proceedings to improve electricity/gas coordination.

These observations are not intended to diminish at all the importance of making sure that electric/gas coordination issues are addressed to prevent the lack of natural gas deliverability from causing a shortage of electricity. Rather, it is to stress that it is important to go about addressing these electric/gas challenges in a manner consistent with competitive wholesale and retail electricity markets that federal and state policymakers have chosen to adopt, and for good reason in terms of delivering affordable electricity at lower risk to consumers.

Finally, EPSA and its member companies have commented to the Federal Energy Regulatory Commission on this important issue supporting various reforms.[2] Broadly speaking all power markets should have in place intraday scheduling opportunities to allow generators to refresh their bids to reflect changing market conditions including gas costs. Reflecting actual market conditions, including unexpected fuel price volatility or system constraints, is necessary to reduce seller's uncertainty regarding adequate compensation when they run and to support ongoing operational and capital investment decisions. EPSA urges that all ISO/RTOs be required to provide price offer flexibility in order to address short run operational issues, as well as ensuring that market participants have confidence in their ability to recover costs and make investment decisions supporting their generation resources.

Conclusion: Advocating the Power of Competition

As the Department of Energy develops the QER and identifies the threats, risks, and opportunities for U.S. energy and climate security, enabling the federal government to translate policy goals into a set of integrated actions, EPSA stands at the ready to continue the dialogue with the department in order to ensure that prices will efficiently signal the appropriate investment and infrastructure needs necessary to ensure continued reliability of the electric system.

As noted in the beginning, notwithstanding the original scope of the QER EPSA is aware of policy and industry issues raised during the forums held across the United States that (in addition to affecting transmission, storage and distribution infrastructure) also directly impact competitive electric generators supplying electricity to the nation's grid. It is with this understanding that we offer these comments and perspective on behalf of our sector for the Department of Energy's consideration and review.

Respectfully submitted,

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[2] Federal Energy Regulatory Commission Post Conference Comments of the Electric Power Supply Association: Commissioner Philip D. Moeller Inquiry into the Trading of Natural Gas, and the Proposal to Establish and Electronic Trading Platform. October 1, 2014 Docket No. AD14-19-000

ATTACHMENT A

Organized Wholesale Markets Require Meaningful Reforms
In Light Of Serious Challenges

Presentation by: Electric Power Supply Association
January 2014

Organized Wholesale Markets Require Meaningful Reforms In Light Of Serious Challenges

Electric Power Supply Association

January 2014

Overview: Why Timely RTO Market Reforms Are Needed

- EPSA supports well-functioning competitive wholesale markets that are economically sustainable to continue providing long-term benefits to consumers
- Reliability in competitive wholesale markets hinges on whether, when and how private capital is invested in existing and new resources; such decisions are being made today that will impact reliability later this decade and beyond
- Investment decisions in organized markets are in significant part made on the basis of long term total cumulative revenue adequacy from energy, capacity and ancillary services markets, which hinges on market design, tariffs and grid operator practices for each RTO and ISO, often the result of past compromises
- Present market design and tariffs do not fully reflect significant structural changes and market conditions that have occurred, are underway, or are expected since present design and tariffs were approved; the impacts of this mismatch are aggravated by certain grid operator practices that undermine market integrity
- Given structural changes, not merely cyclical fluctuations, FERC should focus on long term reliability and therefore should pursue timely RTO market reforms
    - <u>Capacity Markets</u> – not only continue current FERC review of Eastern RTO/ISO markets, but then develop best practices based on public input and require RTOs/ISOs to demonstrate how they have or will satisfy them
    - <u>Energy and Ancillary Services Markets</u> – initiate a similar process leading to best practices based on public input and require RTOs/ISOs to show they have or will satisfy them given the role these markets play in investment decisions and acquisition of necessary resources

Significant Changes Since Current Market Designs and Tariffs Were Approved: Does It All Still Add Up?

- Low load growth has become the new normal going forward
- Natural gas prices result in lower energy market revenues
- Increased amount of resources participating in wholesale markets with out of market revenues
- Increased role for variable and distributed resources impacts revenues and costs for other resources needed for reliability
  - Alters the dispatch mix, lowering capacity factors for many types of resources
  - Squeezes energy and capacity revenues for generation needed to backstop variable resources
  - Stresses many existing units through increased need for cycling and ramping
- Federal and state policies will continue to seek environmental improvements
- Evolving effects of new technologies
  - Level of impacts and timing remain key unknown variables
  - FERC should remain technology neutral in developing market rules
  - FERC has critical role in crafting market rules relating to integration of new technologies consistent with competitive markets and system reliability

Early Warning Signs Are Evident and Compelling

- Current and forward price signals are generally weak, the key question for reliability is why
- *If* weak price signals reflect market fundamentals, then economically unsustainable resources are not necessary for reliability; *however, if*, as happens too often, weak price signals also reflect market design flaws and grid operator interventions, resources needed for reliability in the future are at risk
- Retirements were originally driven by environmental costs impacting older, smaller coal units dispatched infrequently; recent retirements include nuclear and larger, newer or upgraded coal units; and some natural gas plants that are needed to provide future system flexibility face retirement sooner
- Early warning signs indicate that regulatory conditions should be examined generically and appropriate RTO market reforms implemented before the investment climate erodes further

Conclusions

- EPSA strongly supports competitive wholesale power markets, which provide significant consumer benefits but require well-functioning updated market designs and tariffs properly implemented through grid operator practices
- As summarized in the attached appendix, RTO improvements should be pursued in five policy areas: (1) energy and ancillary services price formation; (2) capacity markets; (3) out of market entry and uneconomic supply; (4) demand response; and (5) transmission and seams
- How best to pursue RTO/ISO improvements procedurally?
  - FERC "best practices" policy statements based on public input combined with RTO accountability to show how each RTO satisfies them or will change to meet them could achieve timely reforms in a balanced manner
  - Decisions in individual RTO dockets can be effective on discrete issues; rulemakings may be required but the process is lengthy; and while stakeholder processes are important, they can delay necessary reforms that are critical to address given the challenges facing wholesale markets

APPENDIX ON MARKET REFORM ISSUES AND SOLUTIONS

Background: Nature of Competitive Power Model

- Competition shifts risks from consumers to investors, however resource adequacy is not free under any regulatory model

- Investor risks should be accompanied by the *opportunity* to earn revenues sufficient to recover fixed and variable costs plus a reasonable return on invested capital; there are no guarantees in a competitive market, but nor should there be unnecessary barriers created by market-distorting actions

- Restructuring did not result in "deregulation" as was done elsewhere
  - Wholesale markets have prices heavily shaped by FERC-jurisdictional market designs, tariffs, and operator practices, plus market monitor intervention
  - More uplifted/socialized charges distort accurate price discovery
  - Services are being provided without proper compensation (e.g., reserves, reactive power/voltage support)
  - Bias is toward over-mitigation resulting in high-priced peaks being shaved while downside remains

- Just and reasonable outcomes require improved energy, capacity and ancillary services markets as outlined in detail in subsequent slides

RTO Reforms Needed In Five Key Categories

1. Energy Market and Ancillary Services Price Formation
2. Capacity Market and Resource Adequacy Rules
3. Out of Market Entry and Uneconomic Supply
4. Proper Role for Demand Response
5. Transmission and Seams

Energy Market Price Formation
(markets need accurate price signals)

- LMPs must be allowed to fully reflect market conditions
  - RTOs/ISOs fail to price “reliability” commitments (dynamic markets are disrupting former regime of baseload, mid-merit and peaking plants with increasing use of reliability and other non-priced dispatches)
  - MWs put onto grid for reliability need to be factored into LMPS, un-hedgeable uplift should be minimized, and all constraints need to be modeled in the market
  - All operator actions taken to meet marginal demand should be reflected in LMPs regardless of min/max output levels, etc. (Too often multiple units are dispatched at minimum load)
  - After-the-fact review of dispatch actions would better coordinate operations and markets functions
  - Greater transparency regarding dispatch actions and grid conditions
- Many administratively mitigated prices skew true market prices
  - Bids must be allowed to reflect real time costs
  - Reassessment of components of short run marginal costs
  - Additional intra-power day reoffer or bidding opportunities
  - Reliability commitments should be scheduled day ahead and reflected in day ahead LMPs
  - Proper real time prices will lead load to bid more in day ahead and not only real time

Capacity Market and Resource Adequacy Rules

- Capacity market is for physical not financial resources
- Sloped demand curve to better reflect price and reliability
- Forward procurement period should better align with transmission planning time horizon
- Forward commitment should be at least one year (with careful review of pros and cons of non-discriminatory options for longer pricing periods for a portion of capacity)
- Locational value to signal investment in constrained areas
- Seller-side mitigation must allow long-term fixed costs
- Buyer-side mitigation must prevent undue price suppression
- Transparency and tradability should be enhanced
- Capacity imports into RTOs and ISOs should respect physical and operational reliability limits
- More predictable future capacity market prices are desirable

Out of Market Entry and Uneconomic Supply

- RMR resources should be held out of energy and capacity market price calculations to avoid artificially suppressing market prices
- Careful review required to determine the nature, extent and impacts out of market revenues have on accurate price formation
- Strong MOPR and other buyer-side market power rules will continue to be key market design elements
- *Edgar*-like guidelines for utility self-builds may help ensure fair consideration of market options or else rate-based generation within RTOs distort market outcomes

Proper Role for Demand Response

- Demand response has an appropriate role in electricity markets; given the increased level of demand response that is now participating in RTO markets, the issues going forward revolve around comparable regulation if demand response is to receive comparable compensation
- Ideally demand response should be an energy market, not capacity market, product
- If a capacity market product, demand response should have comparable "must offer" obligations and when called in energy markets be factored into LMPs
- Energy market compensation should reflect savings from foregone retail consumption
- If demand response is allowed in the capacity markets:
  - Comparable basis as a single, annual unlimited physical product
  - Behind-the-meter resources should participate as generation, not masquerading as DR
  - No hold-back percentage from base auctions for later ones

Transmission and Seams

- Greater coordination and transparency between neighboring RTOs/non-RTOs are necessary
- Problems largely stem from historically different approaches to assumptions, modeling, and outage coordination as opposed to technical rationales
- Balancing areas should better align transmission and generation outage scheduling across seams
- Operational and physical constraints must be respected
- Interconnection and transmission service queues should be studied at the same calendar intervals
- Basic modeling elements and assumptions should be consistent across RTOs and non-RTO areas

Attachment B:

The Polar Vortex: Implications for Improving the Efficiency of Wholesale Electricity Spot Market Pricing

A. Joseph Cavicchi, Compass Lexecon, on behalf of EPSA

ATTACHMENT B

The Polar Vortex: Implications for Improving the Efficiency of Wholesale Electricity Spot Market Pricing

By:

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The Polar Vortex: Implications for Improving the Efficiency of Wholesale Electricity Spot Market Pricing

A. Joseph Cavicchi

Prepared for the Electric Power Supply Association

March 2014

I. Summary

Extreme cold weather in early January 2014 provided a stress test for Mid-Atlantic and Northeastern wholesale electricity market designs. Following this unusual polar vortex weather event several important concerns were identified for review and modification.[1] Many of these concerns are appropriately associated with ensuring that independent system operators ("ISOs") have the ability to effectively manage electricity operations during periods when system conditions may be stressed. In addition, the recent cold weather events revealed several electricity spot market[2] pricing inefficiencies which can negatively impact operations and reliability. The polar vortex provides an important opportunity to highlight existing wholesale electric spot market energy pricing inefficiencies, and to embrace future market design policy that will eliminate these problems.

Two particular electricity spot market design inefficiencies were exposed during the polar vortex event. First, the polar vortex illuminated the ongoing problem where uneconomic out-of-market resource compensation ("uplift") puts downward pressure on spot market prices. Although it has been suggested that obfuscating spot market volatility through the payment of uplift is a preferable approach for wholesale electricity market design, the perpetuation of uplift distorts spot market prices and creates incentives for buyers and sellers to deviate away from efficient behavior over both the short and the long run. Since uplift can suppress market prices throughout the year, it can result in the premature retirement of economic resources that are needed during times such as the polar vortex. Some progress has been made over the last several years to formulate and implement more efficient resource commitment and dispatch algorithms that reduce uplift and result in more efficient spot market prices. Additional progress is needed, however, as good market design policy dictates that a concentrated effort be made to minimize uplift.

Second, price caps may have suppressed wholesale electricity market prices below competitive levels. That is, offer and price caps were demonstrably below input costs, and could have prevented spot market clearing prices from reflecting the actual value of electricity supply to the wholesale market. The polar vortex revealed that the expectations which originally formed the basis for a $1,000/MWh price cap were wrong.

[1] The Federal Energy Regulatory Commission ("FERC" or "Commission") has convened a technical conference to review electric system operator experiences during the cold weather events. See Notice of Technical Conference in Docket AD14-8-000, "Winter 2013-2014 Operations and Market Performance in [RTOs and ISOs]," scheduled for April 1, 2014.

[2] The term "spot market" as used herein refers to the day-ahead and/or real-time hourly markets administered by ISOs.

Moreover, once it was clear that rule changes were necessary, there was little time available to do so before reliability may have been adversely impacted. Thus, we have learned from the polar vortex that offer and price caps need to be expeditiously revised.

There are numerous reasons that an immediate permanent response is appropriate to eliminate these inefficiencies. In particular, it is broadly accepted that efficient wholesale electricity spot market design requires that market clearing prices (whether high or low) accurately reflect the marginal cost of balancing supply and demand. Accurate price signals guide market participants to make better decisions. For example, market sellers can make accurate fuel procurement decisions confident that their costs will be covered by spot market prices (e.g., day-ahead and intra-day gas purchases and oil stock decisions) and submit offers that allow efficient dispatch decisions among different resources. Market sellers will also face better short-run performance incentives and see more accurate price signals for longer-term investment decisions including the value of fuel arrangements and dual-fuel capability. In other words, if market prices are predictably allowed to clear at the cost of the marginal unit (both during times of scarcity as well as under normal operating conditions), the market will drive sellers to invest in firmer fuel strategies to ensure performance so that they can avail themselves of the benefits of the more robust markets. At the same time, market buyers will face incentives to submit accurate day-ahead load schedules and to make better hedging decisions. Finally, incentives for demand response will be better aligned with the value of energy.

The polar vortex revealed that electricity spot market price setting rules are inconsistent with sound market design policy. Short-term market rule "fixes" will not resolve the adverse impact of binding price caps on spot market prices. Moreover, ongoing and increased reliance on uplift payments exacerbates spot market pricing inefficiencies, pointing clearly to the need to make a concerted policy effort to reduce these out-of-market payments. The polar vortex illuminated the need to work diligently to resolve ongoing spot market design shortcomings that distort prices. Market design changes should be implemented without hesitation to clearly signal to market participants that electricity spot market pricing will not be distorted by potentially binding price caps and unnecessary uplift.

II. Uplift Payments: The Problem and its Solution

Out-of-market (uplift and make-whole) payments currently are a critical cost-recovery guarantee for market suppliers that took on particular importance during the polar vortex.[3] While uplift payments will increase as a result of the high fuel prices associated with the polar vortex market conditions, it is important to recognize that increased reliance on uplift distorts spot market prices.[4] Contrary to arguments that uplift is a desirable means of protecting consumers from spot market volatility, uplift prevents spot market prices from signaling to market participants the true value of energy and results in price discrimination among sellers. Because uplift distorts spot market prices, good market design policy dictates that uplift payments should be minimized, and market design objectives should seek to ensure that resource commitment decisions are accurately reflected in spot market prices.

Uplift payments arise when an ISO commits a generation resource which operates as directed, but cannot recover its total commitment costs from only spot market revenues.[5] In other words, ex post spot market prices (day-ahead and/or real-time) were not high enough to fully compensate the committed generation resource. The uplift payments created by this uneconomic resource commitment can occur for several reasons. For example, ISOs must ensure that when they award supply resources schedules in the day-ahead spot market, they have sufficient resources to meet forecasted demand. Because day-ahead markets include virtual bidding and the possibility that load bids might underestimate demand day-ahead, ISOs carry out unit commitment reliability checks to ensure sufficient resources will be available during the operating day. In addition, ISO dispatch algorithms incorporate numerous operational constraints, and it can be the case that a resource is dispatched because it is needed for energy, but it may only operate at minimum load, or be committed as block-loaded supply.[6]

However, many resources committed to operate at minimum output levels, or whose dispatch is inflexible, are ineligible to set spot market clearing prices. This means that these resources' supply is part of the market, but the resources' costs are not explicitly

[3] As explained below, both the PJM Interconnection ("PJM") and the New York Independent System Operator ("NYISO") sought and received Commission authorization to "uplift" suppliers whose costs increased as a result of the polar vortex. The Commission has previously authorized ISO-NE to introduce unique winter 2014 fuel expense management, however the polar vortex impact on ISO-NE, although significant, appears to have been manageable (see January 2014 FERC Data Request, ISO New England, System Operations, January 10, 2014).

[4] PJM and NYISO have reported expected increases in uplift; however, final data are unavailable as of early March 2014.

[5] Total operational cost refers to start-up, minimum load and incremental energy costs.

[6] It is important to discern between uplift associated with resource commitments for specific local reliability requirements (e.g., reactive power) and uplift associated with resource commitments to provide energy and/or to guard against potential contingencies. The discussion herein focuses on the latter.

taken into account when setting spot market prices. Moreover, it can often be the case that these resource commitments occur after that time when a resource can nominate natural gas in the more liquid day-ahead market, causing a supplier to procure gas in less liquid intra-day markets, driving up costs and increasing system reliability risk (when compared to receiving a commitment in the ISO day-ahead market). The payment of such costs through uplift rather than the energy price distorts market prices, and it can do so not only under stressed conditions such as the polar vortex, but throughout the year. This persistent price suppression through uplift can result in the premature retirement of economic resources, which in turn exacerbates reliability challenges during operating conditions that stress the electricity system.

A. Uplift Reduction

Uplift is carefully tracked by ISOs. For example, PJM recently established an energy market uplift cost task force that is actively examining the causes of uplift and examining market design changes that will minimize uplift.[7] PJM notes that resource commitments which result in significant uplift are for generating units that cannot set spot market prices, but whose supply was committed to provide energy in association with operational constraints.[8] Similarly, ISO New England ("ISO-NE") reports significant net commitment period compensation ("NCPC") costs (uplift) that result from resource commitments that do not receive adequate revenues from the spot markets.[9] Moreover, because there is often a tendency toward making additional resource commitments to ensure reliable system operations, it is more likely than not that there is extra supply committed.[10] The commitment of additional supply that is compensated out-of-market puts downward pressure on spot market prices.

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[7] See, generally, http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={0584BFB6-F932-44FF-8CBA-AE4320338982}, accessed March 7, 2014.

[8] See, for example, meeting materials for PJM energy market uplift cost task force, November and December 2013, available at http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={0584BFB6-F932-44FF-8CBA-AE4320338982}, accessed March 7, 2014.

[9] See, for example, 2013 Fourth Quarter, Quarterly Markets Report, ISO New England Inc., Internal Market Monitor, February 10, 2014, at 21, where ISO-NE reports that "Economic NCPC is the difference between the cost of committing and operating a generating resource to meet capacity and energy needs in the day-ahead and real-time markets and the energy revenues the resource realizes during the market day." Available at: http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2013/q4_2013_qmr.pdf, accessed March 7, 2014.

[10] For example, ISO-NE notes that "additional capacity was committed in December [2013] to supply energy during extremely cold weather days" (Id). PJM has also indicated in association with its energy market uplift cost task analyses that it is better to have more resources available than fewer (see Uplift in PJM, Adam Keech, PJM Interconnection, February 21, 2014, at 16)

However, the importance of seeking to minimize uplift through better spot market pricing has been the subject of research for several years.[11] The spot market pricing features necessary to account for the costs of resources dispatched at minimum load, or as fixed blocks, are well understood. Recognizing that an efficient electricity spot market design should result in spot market prices that are sufficient to cover the costs of all resources that are committed to provide energy, efforts are being made to minimize uplift.

For example, the NYISO allows fixed block units to be treated as "flexible" during the unit commitment process so that they are allowed to set spot market prices.[12] By allowing fixed block units to set market prices, and receive greater compensation through the energy markets, NYISO reduces uplift that would otherwise be paid to these resources and sets more efficient spot market prices.[13] In addition, the Midcontinent Independent System Operator ("MISO") is nearing implementation of a series of software changes referred to as extended locational market pricing ("ELMP").[14] Under ELMP the MISO will allow certain inflexible resources, particularly gas and combustion turbines, to set spot market prices, reducing uplift and improving spot market efficiency. Finally, PJM represents that its software allows block-loaded resources (combustion turbines) to set spot market prices.[15] Moreover, PJM's energy market uplift cost task force has recommended that software changes be implemented that will allow resources operating at minimum load to set spot market prices.[16] Thus, it is widely understood that prices that reflect the incremental cost of meeting demand, and thereby minimize uplift, provide better spot market price signals for market participants.

[11] See, for example, Gribik, P. R., Hogan, W. W., and Pope, S. L. (2007). Market-Clearing Electricity Prices and Energy Uplift. Available at http://www.hks.harvard.edu/fs/whogan/Gribik_Hogan_Pope_Price_Uplift_123107.pdf.
[12] See, NYISO Market Administration and Control Area Services Tariff ("MST"), 17.1 MST Att B LBMP Calculation Method, 7.0.0, New York Independent System Operator, Inc., as of 03/06/2014.
[13] For example, if high-cost gas turbines are being dispatched to meet load, but their cost is not reflected in market prices, market prices will not send the correct signal for scheduling either imports or exports, or indicate geographic regions where higher-cost supply is needed to meet demand.
[14] See, https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/ELMP.aspx.
[15] See Manual 11: Energy & Ancillary Services Market Operations
Section 2: Overview of the PJM Energy Markets, PJM © 2014, Revision 66, Effective Date: 03/07/2014, at 26.
[16] See, for example, meeting materials for PJM energy market uplift cost task force, November and December, 2013, available at http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={0584BFB6-F932-44FF-8CBA-AE4320338982}, accessed March 7, 2014.

B. Uplift Distorts Buyer and Seller Incentives

Not only does uplift distort market prices, it also creates incentives for market participants to deviate from otherwise efficient bidding behavior. In particular, uplift cost allocation is often complicated and creates incentives for buyers to make decisions that take into account its cost allocation, which can distort bidding behavior. For example, if buyers can benefit from greater reliance on the spot market by shifting costs that end up in uplift onto other market participants, they will seek to do so. Minimizing the incidence of uplift diminishes incentives to alter bidding behavior.

Moreover, uplift can undermine the Commission's objective of relying on nodal pricing to ensure that electric energy markets reflect local conditions. Nodal pricing sends the appropriate price signals for the need for resources at a particular location, including demand response and energy efficiency resources. When ISOs turn to uplift to allocate the cost of energy, the uplift mechanisms do not assign costs at the same level of granularity that locational nodal energy market pricing provides. Instead, uplift cost allocation mechanisms tend to allocate based on the demand customers place on various regions with ISO-controlled transmission systems.[17] Thus, uplift can result in customers in a relatively low-cost location subsidizing the energy costs of customers in higher-priced locations. This is another undesirable result that uplift imposes on market participants, especially end-use customers.

Finally, market participants cannot hedge against uplift charges. Because uplift costs are a function of ISO day-to-day commitment and dispatch decisions and are not reported in a granular fashion (like spot market prices), there is no means by which its costs can be hedged (there are not forward markets for uplift). This means that those market participants that bear the burden of uplift cost allocation, often energy buyers, are exposed to price volatility. However, to the extent that uplift can be minimized by ensuring that spot market prices more accurately reflect actual system resource dispatch cost, buyers can hedge the cost through energy market forward/future contracts. This is a significant benefit for both buyers and sellers. Buyers avoid cost uncertainty and sellers can make forward sales at prices that reflect the true value of energy. This is a win-win outcome for market participants. A sound market design policy objective is to focus on reducing uplift.[18]

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[17] See, for example, Manual 28: Operating Agreement Accounting, Section 5: Operating Reserve Accounting, PJM © 2013, Revision 63, Effective Date: 12/19/2013, at 32-33.

[18] The importance of reducing uplift is reinforced by the 2013 State of the Market Report for PJM which states: "PJM's goal should be to minimize the total level of energy uplift paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of

Improvements in market design that result in reduced uplift and more efficient spot market prices are beneficial. The economic reasoning supporting spot market price setting approaches that incorporate all resources committed to meet demand is straightforward; the costs of supply resources committed to meet energy demand should be taken into account when setting spot market prices. Efficient price signals will provide incentives to sellers to be available and operational in the short run (including supporting fuel procurement decisions) and ensure that economic resources do not prematurely retire as a result of suppressed energy prices. Moreover, any concerns that improved rules for minimizing uplift may increase incentives to exercise market power are not material, as existing rules like those used by the NYISO have demonstrated that more efficient spot market price setting is workable. Although it can be difficult to define precisely the most efficient rules for improving the price setting process, additional progress is required to ensure that uplift payments are not utilized in lieu of competitive spot market prices that truly reflect all costs.

III. Offer/Bid Caps and Spot Market Pricing

An efficient electricity spot market design provides sufficient flexibility to market participants so that they can submit offers that are based on the costs they actually face (including opportunity costs as appropriate) and expect that market prices will be set consistent with those bids and offers accepted by an ISO. Attributes of an efficient electricity spot market design ensure that: offer-caps are consistent with underlying market conditions; gas-electric timelines are realistically accounted for to allow sellers to update bids accordingly and to coordinate commitment and dispatch as necessary; spot market prices are based on the appropriate set of bids and offers; and, any uplift payments are sufficient to cover resource operating costs.

However, market data during the polar vortex show that existing offer and price caps likely prevented wholesale markets from setting efficient electricity prices in portions of the Northeastern U.S. and Mid-Atlantic.[19] Two particular market design issues led PJM and NYISO to file with the Commission emergency requests seeking waivers from certain tariff restrictions. First, PJM and NYISO both sought and received approval to temporarily raise offer price caps above the then applicable $1,000/MWh limit set out in

such charges." (2013 State of the Market Report for PJM, Monitoring Analytics, LLC, March 13, 2014, Volume II, Section 4, Energy Uplift, at 124).

[19] See, generally, PJM Interconnection, L.L.C., 146 FERC ¶ 61,078 (2014) ("PJM Waiver Order"), and New York Independent System Operator, Inc., 146 FERC ¶ 61,061 (2014) ("NYISO Waiver Order"). In addition, volatile natural gas prices also impacted the California Independent System Operator's ("CAISO") ability to ensure efficient market outcomes (see below).

their tariffs.[20] Second, PJM sought and received approval to include in its calculation of spot market prices offers that exceeded the $1,000/MWh offer price cap.[21] Although these waiver approvals ensured that resources would be adequately compensated when costs exceeded historical offer-caps, these emergency measures expire this winter.

The polar vortex event provides an opportunity to recognize these market design flaws and prescribe market design policy initiatives that allow the Commission to act before such an event occurs again.[22] First, out-of-date offer and price cap tariff rules need to be permanently revised to ensure that if short-run marginal costs increase unexpectedly, market offers can be increased accordingly, and market clearing prices can reflect the appropriate value of spot market energy. Second, market offer rules must be sufficiently flexible to allow buyers and sellers to make offers that reflect actual real-time market conditions. There are several sound economic reasons for pursuing tariff changes to eliminate offer and pricing limitations based on out-of-date price caps.

A. Efficient Spot Market Design

First, the foundation of centralized electricity spot market design is the use of a uniform clearing price auction to set prices based on market participant bids and offers. The uniform price market design ensures that wholesale electricity market welfare is maximized by setting electricity spot prices at the level where buyers and sellers have no incentive at the margin to buy or sell more energy.[23] That is, prices are set such that the market clearing price represents an "equilibrium" price. All buyers and sellers transact based on the same transparent spot market prices, ensuring that all market participants are treated equally.

Basic economics teaches that binding price caps prevent a uniform clearing price auction from establishing a market clearing price that is efficient and non-

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[20] Id.

[21] PJM Waiver Order at P 38. In its waiver request the NYISO indicated that it could not request authority to allow offers above $1,000/MWh to set spot market prices as its software could not readily support this modification (NYSIO Waiver Order at P 15).

[22] In its waiver approvals the Commission did not order any immediate ISO initiatives; stakeholder processes are expected to begin to consider permanent market rule revisions.

[23] It has been widely established that an electricity market design using bid-based, security constrained, economic dispatch with locational marginal prices and financial transmission rights will provide those features necessary for an open and transparent marketplace (see, for example, International Energy Agency ("IEA"), Tackling Investment Challenges in Power Generation in IEA Countries: Energy Market Experience, IEA, Paris, 2007, at 18-21). All U.S. ISOs use this market design framework, which establishes uniform market clearing prices for all buyers and sellers (differentiated as appropriate to account for losses and congestion), and the Commission has consistently endorsed this market design.

discriminatory.[24] For example, capping offer prices used in the calculation of spot market prices means that prices will not reflect market conditions when underlying marginal costs increase and offers rise above $1,000/MWh (offer prices are capped in the spot market price calculation). In electricity spot markets, this means that accepted offers above the price cap must be compensated through uplift, which results in price discrimination and market price distortion. However, the Commission has consistently stated "[p]ayments made only to individual resources and recovered in uplift fail to send clear market signals," and that those resource costs "should be reflected in transparent market prices whenever possible."[25] Moreover, the Commission noted in its recent order approving PJM's waiver request that "By limiting legitimate, cost-based bids to no more than $1,000/MWh, the market produces artificially suppressed market prices and inefficient resource selection."[26] Clearly, preventing legitimate offers above binding offer price caps from setting market clearing prices is distortionary.

Important benefits flow from efficient spot market prices. By revealing to sellers the actual value of energy production, sellers are provided the best incentives to be available, to operate reliably, and to enter into forward market sales contracts. At the same time, by revealing to buyers the actual value of consumption of spot market energy, buyers will be less likely to rely on the spot market and seek to shift costs onto others, and be more likely to enter into forward market hedges. Moreover, by setting efficient spot market prices, the spot market design guides medium and longer-term power purchase and sale decisions that tend toward more optimal resource allocation.

For example, electricity spot market prices that are allowed reflect high marginal cost supply provide market sellers assurance that their costs will be covered by spot market prices and more efficiently guide firm fuel procurement decisions such as day-ahead and intra-day gas purchases and oil supply restock decisions. In addition, reducing seller uncertainty regarding receipt of adequate compensation for providing electricity will improve seller creditworthiness and ensure that fuel supply can be readily purchased when prices are volatile. Accurate price signals will also provide sellers stronger performance incentives and provide more effective signals for longer-term investment decisions, including the value of fuel stocks and dual-fuel capability. Moreover, efficient prices are an important signal as to where, when, and how much new capacity may be

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[24] It is a basic economic principle that price caps will result in shortages by discouraging sellers from offering supply to the marketplace (see, for example, Mankiw, N. Gregory, Principles of Microeconomics, Fourth Edition, Thomson South-Western, 2007, at 114-117). Although electricity spot market design seeks to circumvent this problem with uplift payments, distortionary effects remain as seller marketplace expectations are altered by the price caps.

[25] *PJM*, 139 FERC ¶ 61,057, at P 78, n.72.

[26] PJM Waiver Order at P 40.

economical. Higher prices often indicate that the introduction of newer, more efficient resources is likely to be profitable. Existing resources facing accurate prices can make better ongoing operational and capital investment decisions.

In addition, ensuring efficient spot market pricing reduces the incentive market participants face to take actions that distort market clearing prices. For example, if spot market prices omit certain costs, or are capped at levels below the actual value of energy to the marketplace, buyers will take this into account in their decision-making. Buyers can avoid payment for higher-cost energy by relying more on the spot market and shifting these costs (collected through uplift) onto other market participants that are likely to have hedged.[27] Such cost shifting results in price discrimination, which is clearly against Commission policy.[28] It also undermines the value of a hedge, since uplift cannot be hedged, which discourages customers from hedging as they will be paying for a product that is not capable of giving them the value they require. However, efficient spot prices provide incentives to market buyers to accurately schedule load and to make better hedging decisions.[29] At the same time, buyers can make better decisions about the benefits of hedging and the value of forgoing consumption when prices are high.

Finally, in addition to allowing market clearing prices to reflect offers that may be above outdated offer price caps, market participant offers used to determine spot market clearing prices must reflect current market conditions. This is especially relevant in two ways. First, efforts that are currently underway to better coordinate gas and electric markets require increased offer flexibility to accommodate gas price variation between day-ahead and day-of scheduling and delivery times.[30] Second, in instances where daily gas price volatility is high it is critical that ISOs use appropriate

[27] This behavior is not hypothetical, as these kinds of uplift cost allocation debates occur frequently. See, for example, ongoing market design modifications being pursued by ISO-NE in association with uplift: NCPC Cost Allocation: Phase 1 - Strengthen Incentive for Load to participate in the Day-Ahead Energy Market ('DAEM'), by Catherine McDonough, http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2014/mar12132014/index.html, accessed March 25, 2014.
[28] See, for example, *Blumenthal v. ISO New England*, 117 FERC ¶ 61,038, at P 83.
[29] Virtual bidders also face distorted price signals and possible misallocation of costs resulting from inefficient physical buyer and seller bidding behavior.
[30] There are a series of important issues associated with gas-electric coordination. The focus herein is on assuring that supplier offers have sufficient flexibility to change offers to reflect gas market price volatility.

fuel prices when setting cost-based offers.[31] Offer flexibility is critical for ensuring that market participants can adjust offers as appropriate to reflect market conditions.

B. Supplier Spot Market Offer Flexibility

The importance of supplier offer flexibility and efficient pricing has been a long-standing market design issue that the NYISO has worked to address. The NYISO tariff currently provides market participants the flexibility to structure and modify supply offers consistent with underlying costs. In particular, the NYISO permits sellers to adjust real-time offers to account for fuel price volatility between the day-ahead and real-time markets.[32] This ensures that generators are able to reflect actual fuel prices in their adjusted offers, which was of particular importance in the context of the polar vortex experience due to the volatility of natural gas prices during that time. The offer flexibility that NYISO provides is an example of good market design policy, though it was impaired by the current $1,000/MWh offer cap as discussed above.

However, the NYISO is the exception. Given New England's growing reliance on natural gas electric generation resources, ISO-NE has pursued tariff changes to provide sellers greater offer flexibility to better accommodate fuel market price volatility. Although the Commission conditionally approved ISO-NE's tariff changes to improve offer flexibility in October 2013, these changes have yet to be implemented, though it is hoped that they will improve sellers' ability to reflect real-time fuel costs, as occurs in NYISO.[33] Most recently, gas price volatility and supplier offer restrictions have significantly impacted the CAISO. On March 4, 2014, certain CAISO suppliers filed an emergency request for temporary waiver, explaining that compliance with CAISO dispatch directives was resulting in significant unrecoverable fuel expenses.[34] Just two days later, on March 6, 2014, the CAISO filed emergency waiver requests in an apparent effort to assure sellers that they will not be committed and dispatched and unable to recover their costs.[35] However, contrary to the relief requested by the CAISO

[31] These two concerns significantly overlap; however, they have arisen in different contexts when considering the polar vortex experience in comparison to recent cost recovery issues in the CAISO market.
[32] See New York Independent System Operator, Inc. - NYISO Tariffs - Market Administration and Control Area Services Tariff (MST) Services Tariff, section 23.4.7.
[33] ISO New England Inc. and New England Power Pool, 145 FERC ¶ 61,014(2013).
[34] See, Indicated CAISO Suppliers, Emergency Request for Temporary Waiver and Shortened Comment Period, Docket No. ER14-1428, March 4, 2014.
[35] See, California Independent System Operator Corporation, Petition for Limited Waiver of Tariff Provisions and Request for Next Day Commission Action, Docket ER14-1442, and Petition for Limited Waiver of Tariff Provisions, Request for Shortened Comment Period, and Request for Expedited Commission Action by March 19, 2014, Docket ER14-1440, March 6, 2014.

suppliers, the CAISO's waiver request proposes only limited instances where fuel price volatility will be acknowledged and therefore will continue to leave suppliers exposed to losses when following CAISO dispatch instructions. Suppliers need to be provided assurance that they will be fully compensated for performance with dispatch directives.

It is clear that seller incentives to competitively offer supply to the market require that sellers be permitted to submit supply offers consistent with actual costs, and be compensated appropriately. Providing offer flexibility that allows hourly differentiation of day-ahead and real-time offers reduces financial risks faced by sellers and provides an ISO with greater assurance that sellers will have an incentive to follow commitment and dispatch awards. The ability to incorporate gas price variation between the day-ahead and real-time spot markets will improve ISO commitment and dispatch decisions (e.g., less uncertainty regarding cost recovery will allow more accurate bids which should improve commitment and dispatch). In addition, in instances where seller resources have dual-fuel capability, improved flexibility should provide better signals for fuel switching decisions. Moreover, offer flexibility results in spot market prices that better reflect actual fuel supply costs (see above).

C. Criticisms Against Efficient Spot Market Pricing Are Unfounded

Various criticisms have been put forth as a basis to continue the "status quo" offer price cap and spot market price cap limits. For example, it has been suggested that the offer and price caps are essentially a market feature that market participants ought to expect will not be subject to change (at least not quickly), and that instances where seller costs exceed the cap can be collected through uplift.[36] In addition, it has been suggested that allowing spot market prices to be set based on offers above $1,000/MWh will materially increase buyer costs and create incentives for both gas sellers and electricity market participants to raise prices un-competitively.[37] Moreover, it has been suggested that relaxing offer and bid caps affects hedging decisions and can result in increased exposure to high prices.[38] None of these arguments provides a sound economic basis to perpetuate out-of-date offer and market price caps.

Historically, offer and price caps were set at $1,000/MWh under the expectation that this level was sufficiently greater than historically observed supplier short-run marginal costs and would provide fail-safe protection against the possible exercise of

[36] See, for example, PJM Waiver Order at P 21.
[37] Id. at PPs 19 and 23.
[38] These concerns were specifically raised in the context of PJM's waiver request that sought authority to include offers above $1,000/MWh in the determination of spot market prices.

market power.[39] However, the polar vortex event demonstrated that the historical basis for the offer/price cap is no longer valid.[40] The simple fact that seller costs could credibly increase, causing the historical offer/price cap to bind, provides a reasoned economic basis to relax the offer/price caps. It is clear that market expectations have now changed.

Next, it has been suggested that "unlimited" price exposure could result if offer and price caps are relaxed so that spot market prices can be set based on offers above $1,000/MWh.[41] This assertion is misplaced. First, as explained above, an efficient market design requires that prices be consistent with underlying market conditions. Second, market power monitoring and mitigation has been substantially refined since the establishment of the $1,000/MWh offer cap.[42] The original purpose of the offer caps was to mitigate seller market power; however, there is no mitigation purpose being served by preventing sellers from submitting cost-based offers. In addition, extensive market power mitigation rules will continue to guard against artificially increased prices; the Commission acknowledged the importance of ongoing market power monitoring and mitigation in its PJM waiver order as well as its ISO-NE offer flexibility order.[43] Third, buyers and sellers will continue to enter into hedging contracts that provide financial protection against spot market price volatility. Actual consumer exposure to spot market prices is limited, and numerous contractual instruments are available to buyers and sellers to hedge spot market price volatility.[44]

Finally, arguments that reference prior reliance on particular hedging strategies by buyers and sellers as a reason for maintaining offer and price caps are not economically

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[39] See, for example, Answer of PJM Interconnection, L.L.C., to Comments and Protests, Commission Docket No. ER14-1145-000, February 3, 2014, at 6-7.
[40] See, Id. at 1 and Petition for Temporary Tariff Waivers, Request for Shortened Comment Period, and Request for Expedited Commission Action by January 31, 2104, New York Independent System Operator, Inc., Docket No. ER14-1138-000, January 22, 2014, at 3.
[41] PJM Waiver Order at P 22.
[42] See, for example, Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets, The Brattle Group, September 14, 2007.
[43] PJM Waiver Order at PPs 42-43 and ISO New England Inc. and New England Power Pool, 145 FERC ¶ 61,014(2013), at P 37.
[44] The majority of smaller electricity consumers in the Northeastern and Mid-Atlantic U.S. obtain retail electricity through standard offer service (also referred to as default or basic generation service), which is almost exclusively procured by utilities under fixed price supply contracts of various terms. Other larger customers actively seek service from competitive retailers and understand the costs and benefits of hedging. Finally, numerous electricity spot market hedging instruments are available to buyers and sellers (see, for example, http://www.cmegroup.com/trading/products/#pageNumber=1&sortField=oi&sortAsc=false&page=1&subGroup=11).

sound. Allowing legitimate costs to be reflected in market clearing prices will ensure that strategies of relying on spot markets and the prospect of shifting uplift costs to others is not beneficial. Moreover, sellers will not, and should not, be expected to use hedges to keep spot market prices artificially low. Buyers and sellers will seek all profitable transactions taking into account current opportunity costs, not the historical cost or benefit associated with a pre-existing hedging arrangement.[45]

In summary, the polar vortex event revealed that there are critical aspects of electricity spot market rules that are inconsistent with sound market design policy. Short-term market rule "fixes" will not resolve the adverse impact of out-of-date price caps on spot market prices. Moreover, ongoing and increased reliance on uplift payments exacerbates spot market pricing inefficiencies, pointing clearly to the need to make a concerted policy effort to reduce these payments. The polar vortex illuminates the need to work diligently to resolve ongoing spot market design shortcomings that distort prices. Market design changes should be implemented without hesitation to provide clarity to market participants that spot markets are intended to price spot electricity consistent with underlying market conditions.

[45] To be clear, buyers and sellers will take into account their net market positions (which includes hedging contracts) when making short-run decisions, but it will be the costs and benefits at the margin that inform these day-to-day and hour-to-hour decisions.

Attachment C:

POST-CONFERENCE COMMENTS OF THE ELECTRIC POWER SUPPLY ASSOCIATION Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators. May 14, 2014. Federal Energy Regulatory Commission Docket No. AD14-8-000

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators	))))	**Docket No. AD14-8-000**

POST-CONFERENCE COMMENTS OF
THE ELECTRIC POWER SUPPLY ASSOCIATION

The Electric Power Supply Association ("EPSA")[1] respectfully submits these comments in response to the Federal Energy Regulatory Commission's ("FERC" or "Commission") March 19, 2014 notice establishing a date for submittal of post-conference comments following the April 1, 2014 technical conference in the above-captioned proceeding.[2] The purpose of the April 1 technical conference was to explore the impacts of recent cold weather events on the Independent System Operators and Regional Transmission Organizations ("ISOs" or "RTOs"), and discuss actions taken to respond to those impacts.[3] EPSA commends the Commission for scheduling this conference, which was beneficial in looking broadly across the wholesale electricity

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1 EPSA is the national trade association representing leading competitive power suppliers, including generators and marketers. Competitive suppliers, which collectively account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities. EPSA seeks to bring the benefits of competitlon to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

2 *Supplemental Notice Of Technical Conference*, Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators, Docket No. AD14-8-000, (issued March 19, 2014) ("March 19 Notice").

3 *Notice of Technical Conference*, Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators, Docket No. AD14-8-000, (issued February 21, 2014) ("February 21 Notice").

markets (as well as the natural gas markets) to identify market and operational issues that need to be addressed, and to share lessons learned. In particular, the conference underscored that certain critical market design elements, tariff rules and operator practices are creating distortions that erode the efficiency of market operations and reliability. Therefore these critical matters must be addressed by the Commission and by individual ISOs/RTOs under the Commission's oversight on an expeditious timeline. EPSA urges swift adoption of the reforms and clarifications discussed in these comments in order to ensure that prices will signal the appropriate investment necessary to continue to ensure the reliability of the electric system as it evolves. This is especially important to achieve soon given that investment decisions informed by price signals are being made on an ongoing basis. To that end, EPSA strongly urges the Commission to establish expeditious timelines for appropriate action by the Commission and the ISOs/RTOs for each of the issues discussed below.

I. EXECUTIVE SUMMARY AND OVERVIEW

While held to discuss issues and concerns posed by extreme weather and polar vortex events over the winter of 2013-2014, the clear takeaway of the technical conference held at FERC on April 1, 2014, is that while the system was stressed, the electricity supply and delivery system met reliability needs under those extreme conditions. However, policymakers and market participants must consider how the marketplace and regulatory framework are changing to ensure that the system will continue to maintain reliability in extreme winter weather in the future, not to mention during normal weather conditions. Thus, as noted by panelists at the conference and supported by subsequent discussions and presentations referenced below, there are critical market design and operational issues known for some time which require immediate attention and satisfactory resolution in order to ensure system reliability more efficiently going forward. Regardless of whether these issues may have shorter or longer term impacts, the Commission needs to take action to address them, as investments and operational decisions are being made today that will impact system reliability several months and years down the road.

Many of the needed reforms were highlighted in sharper relief by the extreme weather this past winter, but are not simply weather-related concerns. Rather, numerous market design issues transcend extreme weather conditions, and were, in fact, apparent as far back as last fall at the Commission's technical conference on ISO/RTO capacity markets held on September 25, 2013.[4] While convened to examine certain periodic capacity markets, broader concerns about the ongoing wholesale energy markets which determine generator dispatch and most revenues were identified for review and corrective action by the Commission and the regional ISO/RTO markets. To that end, EPSA submitted detailed post-conference comments to draw attention to the energy market issues that are inextricably linked to the capacity market issues, as several speakers pointed out last September.[5]

That array of time-sensitive market design, tariff rule and operator practices reforms is also reflected in an EPSA presentation posted on its website in January,

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4 *Notice of Technical Conference,* Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, Docket No. AD13-7-000, (issued June 17, 2013) ("September 2013 Capacity Markets Technical Conference").

5 *Comments of the Electric Power Supply Association,* Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, Docket No. AD13-7-000, at pages 2-13, 35-42, (filed January 8, 2014) ("EPSA Capacity Markets Post-Conference Comments").

having been developed over the course of 2013 by a working group of EPSA member company experts reporting to EPSA member company senior management. That presentation, "Organized Wholesale Markets Require Meaningful Reforms in Light of Serious Challenges,"[6] included here as Attachment A, outlines a detailed roadmap of those actions needed to repair the market flaws creating dangerous distortions in the ISOs/RTOs. As noted in the EPSA presentation, revenues across all of the markets (energy, capacity and ancillary services) were significantly low by historical standards in recent years. Despite very recent indications of some recovery, wholesale power prices remain well below where they were prior to the dramatic fall-off following the economic crisis of 2008 and the shale natural gas revolution. To be sure, the drop in wholesale power prices by as much as half or more from peak levels reflects in large part a changing landscape for power generation based on numerous factors outside of the Commission's or ISO's/RTO's control.[7] Compounding these external dynamics, however, are market design and operator actions that further suppress wholesale prices below levels reflective of market fundamentals. This artificial or administrative price suppression creates flawed investment signals, both short-run and long-run, potentially

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6 Attachment A, *"Organized Wholesale Markets Require Meaningful Reforms in Light of Serious Challenges,"* Electric Power Supply Association presentation, (posted January 9, 2014), also *available at* www.epsa.org, ("EPSA Market Reform Presentation").

7 *See* EPSA Capacity Markets Post-Conference Comments at pages 6-9; *also see* "Capacity Markets in the Northeast: A Preview of Comments at the FERC Technical Conference on Centralized Capacity Markets in RTOs/ISOs," presentation by Dr. Susan F. Tierney, Managing Principal of the Analysis Group, at the Independent Power Producers of New York ("IPPNY") Fall Conference (September 10, 2013) at Slide 13. (Slide 13 lists the array of external factors exerting downward pressure on energy prices and revenues. Importantly, many of these factors are structural, not merely cyclical, so will endure for some time going forward.) *Available at* http://www.ippny.org/uploads/PDF/1378921415_TierneyPresentation_Fall2013.pdf.

adversely impacting the investment decisions made by market participants and therefore potentially impacting the reliability and resiliency of the grid in the future.

As had been expressed last September, EPSA does not stand alone in its focus on needed market reforms, a perspective that has been bolstered by the stress test of this past winter. In an unprecedented joint letter from EPSA together with the Edison Electric Institute and the Nuclear Energy Institute submitted to the Commission in this docket on April 23, 2014, the presidents of all three organizations noted,

> Our ability to maintain system reliability faces new challenges associated with the changing generation fuel mix. Reliability rests on a mix of baseload, mid-merit and peaking generation using a variety of fuels and technologies. FERC reforms of competitive wholesale power markets as to market design, tariff rules and grid operator practices are necessary to improve investment signals for existing and new generation resources as well as grid infrastructure consistent with maintaining this grid reliability.[8]

The trade associations encourage the Commission "to continue its efforts to address the issues highlighted by last winter's extreme weather and also those that are not weather-specific." While some issues may have shorter term impacts and therefore require shorter deliberative processes, all of the market design flaws, troublesome tariff rules, and counter-productive ISO/RTO operator practices identified over recent months require a public game plan for action and resolution including date-specific milestones for the Commission and the ISOs/RTOs under its jurisdiction.

Investment decisions in organized markets are in significant part made on the basis of forecasted and actual long term total cumulative revenue from energy, capacity

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[8] Electric Power Supply Association, Edison Electric Institute ("EEI") and Nuclear Energy Institute ("NEI") Joint Letter to the FERC on necessary Electricity Market Reforms, Docket No. AD14-8-000, (April 23, 2014), *available at* www.epsa.org.

and ancillary services markets, which hinges on market design, tariffs and grid operator practices for each ISO and RTO. Given the serious concerns expressed at the April 1 conference, in EPSA's January 2014 market reform presentation, and as far back as the September 25, 2013 capacity markets conference, it is imperative that the Commission take meaningful action to ensure that the market participants the system relies on have sufficient confidence that needed reforms are being addressed now and will be resolved soon. In the absence of tangible policy and market rule undertakings, market participants have no choice but to assume for business planning purposes that improvements will not be forthcoming where necessary. This is not tenable; Commission dockets increasingly demonstrate that reforms are urgently needed. It is important to stress that reliability, properly defined, is based on a dynamic mix of baseload, mid-merit and peaking generation each from a variety of fuels and technologies. For example, baseload needs can be met by coal, natural gas and nuclear plants. Similarly, certain coal plants sometimes now operate in a more traditional mid-merit or peaking fashion. Furthermore, increased generation from renewables both supplies some of these needs and impacts the necessary composition of the remaining mix. Market reforms should reflect this practical and inclusive approach to fuel diversity and reliability.

The identified issues detailed below are an important part of the effort required to strengthen accurate investment signals for existing and new generation resource options as well as broader grid infrastructure investments consistent with maintaining grid reliability. Hence, EPSA is heartened by recent statements acknowledging the need to address critical market issues. In closing remarks at the April 1 conference, FERC Chairman Cheryl LaFleur noted,

> One of the comments that was made today that really stayed with me was when Abe [Silverman, NRG] said this winter we saw cracks in the market foundation. If you don't address little cracks, they become big cracks....And we will pledge to give it the priority that it needs when those things come in, and to participate in any way in helping to solve those things. Because this is definitely worth the effort that it will take to come up with the right fixes and address them.[9]

A week and a half later, Chairman LaFleur testified before the U.S. Senate Committee on Energy and Natural Resources, stating, "[A]lthough the drivers of power supply changes are largely outside of FERC's jurisdiction we must work to ensure the energy industry and markets adapt to these developments in order to carry out our statutory responsibilities."[10] EPSA agrees.

EPSA welcomes and supports FERC's leadership and action to achieve improvements to market design, tariff rules and grid operator practices, and will continue to work with the Commission and the regional markets to develop and implement solutions on a timely basis. The Commission's procedural options to accelerate timely market improvements are many, and all steps should be employed as necessary and appropriate (e.g. individual ISO/RTO cases on specific issues, broadly applicable best practices and policy statements with mechanisms for ISO/RTO accountability, rulemakings, and general oversight). In particular, EPSA encourages the

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9 April 1 Technical Conference Transcript, page 293, lines 10-13, 18-22.

10 Testimony of Cheryl A. LaFleur, Acting Chairman, Federal Energy Regulatory Commission, Hearing of the U.S. Senate Committee on Energy and Natural Resources: "Keeping the Lights on – Are We Doing Enough to Ensure the Reliability and Security of the U.S. Electric Grid?, " at page 9, (April 10, 2014), *available at* http://www.ferc.gov/about/com-mem/lafleur.asp.

Commission to continue to act in individual RTO dockets on timely market improvements consistent with these comments and the sound market principles on which they are based.

II. POST-CONFERENCE COMMENTS

As noted above, this past winter highlighted several key market concerns which require action from the Commission and the ISOs/RTOs. Importantly, many of these market flaws are operational issues which tend to intersect under the umbrella of energy market price formation[11], as highlighted previous to this winter's extreme weather events.[12] It is encouraging, therefore, that some ISOs/RTOs are currently addressing energy price formation in part or in whole, but more must be done and faster because ISO/RTO energy markets provide the majority of generator revenues.

For instance, with the Commission's approval, this year MISO is implementing a version of Extended Locational Marginal Pricing ("ELMP"), which is designed to improve how Locational Marginal Prices ("LMPs") and market clearing prices ("MCPs") are

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11 Capacity markets also face price suppressing mechanisms. The serious impacts of price suppression in the capacity markets are highlighted, for example, in the "Analysis of the 2016/2017 RPM Base Residual Auction," issued April 18, 2014, by Monitoring Analytics, the Independent Market Monitor ("IMM") for PJM. The IMM analysis states at page 5: "The combination of the Short-Term Resource Procurement Target and inferior demand side products had a significant impact on the auction results...The use of the Short-Term Resource Procurement Target together with the inclusion of the Limited and Extended Summer DR products resulted in a 65% reduction in RPM revenues for the 2016/2017 RPM Base Residual Auction" (emphasis added). *Available here* www.monitoranalytics.com.

12 *See generally* September 2013 Capacity Markets Technical Conference Transcript, *available here* http://www.ferc.gov/CalendarFiles/20131023141539-Transcript%209-25-13.pdf, and the Pre-Conference Statement of Michael M. Schnitzer, Co-founder and Director of The NorthBridge Group, Docket No. AD13-7-000, (filed September 9, 2013). Mr. Schnitzer participated on Panel 4: Considerations for the Future, on behalf of EPSA at the September 2013 Capacity Markets Technical Conference. *Also see* EPSA Capacity Markets Post-Conference Comments and EPSA Market Reform Presentation.

calculated for the energy and ancillary services markets.[13] In a similar attempt to improve how market prices are calculated, NYISO has been utilizing Hybrid Pricing for over a decade with the Commission's approval. In PJM, the RTO established Perfect Dispatch on its own, which is an *ex post* review to compare actual dispatch results to those which would have occurred with the benefit of hindsight. This is designed to improve the accuracy of dispatch decisions over time and thus reduce uplift based on dispatch choices including out of merit dispatch that result in uplift.[14] EPSA's understanding is that this tool has proven helpful in matching up the otherwise distinct markets and operations functions within the RTO. There are no doubt other enhanced energy market pricing improvements to be explored with the goal of achieving more accurate and transparent price formation across all ISOs/RTOs based on these best practices and options.

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[13] *Midwest Independent Transmission System Operator, Inc.*, Order Conditionally Accepting Tariff Revisions, 140 FERC ¶ 61,067, Docket No. ER12-668, (2012) ("MISO ELMP Order"). *Also see* MISO Frequently Asked Questions ("FAQs") Sheet on ELMP at page 1: "The key improvement of ELMP over MISO's current price calculation method is that ELMP allows Fast Start Resources that are either scheduled at limits or offline to set price. In addition, ELMP allows Emergency Demand Resources ("EDRs") to set price in the Real Time Energy and Operating Reserve Market. Both Start-Up/Shut-Down Offer costs and No-Load Offer costs will be reflected in the LMPs and MCPs set by Fast Start Resources. The software implementation of ELMP is often referred to as SCED-Pricing, the SCED-Pricing algorithm, or the SCED-Pricing engine. SCED-Pricing is defined in a new Schedule 29A in the Tariff." *Available here* https://www.midwestiso.org/Library/Repository/Communication%20Material/Strategic%20Initiatives/ELMP%20FAQs.pdf.

[14] *See* PJM Perfect Dispatch Fact Sheet dated February 6, 2014: "PJM Interconnection developed a Perfect Dispatch process as a way to analyze the efficiency of its dispatch operations and to spur continuous improvement in dispatching. The Perfect Dispatch metric is a measurement of the ability of dispatch operations to minimize PJM's system production cost while meeting reliability requirements...

"...While hypothetical and not realistically achievable, the calculated Perfect Dispatch serves PJM as a valuable baseline for measuring performance and identifying opportunities to improve the dispatching process. The metric compares the calculated daily production cost to the actual real-time daily production cost to derive a "percentage of perfect" score." *Available here* http://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/perfect-dispatch-fact-sheet.ashx.

Although expanding the use of these pricing mechanisms would be beneficial, they do not go far enough to improve price formation, reduce out of market intervention, improve transparency over operator actions and price formation inputs, and minimize uplift to ensure that market prices signal efficient investment and retirement decisions that will support reliability going forward. As discussed further below, there remain persistent problems in every ISO/RTO related to overreliance on uplift payments, constraints created by existing offer caps, and insufficient generator offer flexibility including as to intraday fuel switching.

Therefore, each ISO/RTO should be required to demonstrate to the Commission's satisfaction that it has a plan in place or in development to deploy whatever mechanism or combination of steps will assure accurate electric energy market price formation so that investment decisions are based on the true costs and value of providing reliable grid operation in the wholesale power markets. At present, too many operator actions taken in the name of reliability are not reflected in LMPs.

While each RTO may utilize or consider different approaches, the shared goal is to ensure that market clearing prices reflect economic fundamentals at a level which includes the revenues required to support the long term nature of power generation investments in a competitive market. To do so, generally speaking, market clearing prices must reflect all units committed by the market operator, capturing all costs and MWs of those committed units. While seemingly straightforward, there is an array of market rules and practices that disallows the full costs or value of particular resources from setting the market clearing price during certain types of operating conditions. Examples of unit commitments not included in hourly LMP energy prices are: out-of-merit order dispatchable plants committed at minimum levels to maintain ramping capabilities; units committed to resolve local reliability conditions; fast-start resources or DR resources committed during tight market operating conditions; and reliability must run units.[15] Certain ISOs/RTOs have recognized these issues, though timely and specific resolution to these problems is required from FERC. Several weeks ago, five RTOs met in California for the "California ISO Market Pricing Forum,"[16] in which the market operators and stakeholders discussed how forward and real-time electricity prices are formed, and how those processes can be improved and made more transparent. This forum represents a notable acknowledgement of this important issue and the need for reforms. Each RTO faces certain challenges, and some have looked at ways to improve their pricing approach to address those challenges.[17] Sharing information and ideas is an important first step in the right direction, and EPSA and its members will work with ISOs/RTOs in this and other venues to address these issues. Although the ISOs/RTOs have in some instances initiated efforts to evaluate concerns with price formation, it is imperative that the Commission take concrete action to pursue market changes that can aid in the resolution of these issues. A greater sense of urgency is required – getting prices right should be a primary objective for supporting system reliability under all weather conditions. Some discussion at the California forum

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15 Comments of Susan F. Tierney, PhD., Managing Principal, Analysis Group, on her own behalf, Considerations for the Future of Centralized Capacity Markets, *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators,* Docket No. AD13-7-000, (filed September 9, 2013), at page 6.

16 California ISO Market Pricing Forum, April 22, 2014, agenda and presentations available here http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=BF4A640C-4C1D-410C-BA1C-4391F317E513, ("CAISO Pricing Forum").

17 See e.g., MISO's ELMP in Docket No. ER12-668-000 (this is expected to reduce, but not eliminate, uplift when implemented) and PJM's Perfect Dispatch.

suggested follow up steps taking *years* to implement. To be clear, this slow pace is unacceptable and untenable given the overwhelming evidence that distorted market pricing impairs business decision-making.

As highlighted at the April 1 conference, there are several particular issues that should be addressed now and therefore require timely direction or guidance from FERC by policy statements, rulemakings, or otherwise as appropriate.

A. Uplift Payments

Ongoing concerns among EPSA member companies are market design and rule flaws that have been suppressing or artificially skewing energy market prices for several years. These flaws existed before the winter of 2013-2014, but have been highlighted for all stakeholders by the stress to the system this winter. This has reached a critical juncture as revenues across the electricity markets have been historically low for several years, certainly compared to all-in fixed and variable costs for many types of power plants. While market fundamentals several years ago produced more robust results which masked some of these market flaws, under current market conditions the adverse impact of these flaws is more apparent. First and foremost, therefore, reliance on out-of-market uplift payments to generators must be addressed.

Even in the normal course of business, grid operators frequently take actions without transparency and accountability to call on resources outside of economic merit order that are compensated through separate uplift payments rather than through LMPs. That uplift cost is spread among load (and sometimes certain generators) outside of the LMP mechanism, creating an unhedgable cost to many customers, and dampening the investment signal sent by LMPs because distorted LMPs result in similarly inaccurate forward prices on which investment decisions as to existing and new resources are in large part made. Further, uplift is only paid to the resource receiving it which undermines the value of the single clearing price mechanism FERC has approved for ISOs/RTOs by distorting market price signals, thereby dampening the investment signal through inaccurate forward prices based on distorted LMPs.

Across the board, each ISO/RTO reported that they experienced great amounts of uplift this winter. This was caused by a range of actions and circumstances, including more than expected net interchange available in real time, changes to fuel prices in real time, and minimum operating requirements and run-times, etc. Regardless of the cause, the reliance of market operators on uplift payments damages the market by distorting the market price. According to A. Joseph Cavicchi, Executive Vice President, Compass Lexicon, in a recent paper for EPSA on the polar vortex included here as Attachment B, "the perpetuation of uplift distorts spot market prices and creates incentives for buyers and sellers to deviate away from efficient behavior over both the short and the long run. Since uplift can suppress market prices throughout the year, it can result in the premature retirement of economic resources that are needed during times such as the polar vortex."[18] While keeping overall market prices artificially low during times of high fuel prices may be attractive in the short run, this leaves certain customers without the ability to hedge their purchases, and it does not reflect the full range of resource commitment decisions actually made by the ISO/RTO grid operators, thereby preventing market prices from signaling the true value of energy for consumers

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[18] Attachment B, "*The Polar Vortex: Implications for Improving the Efficiency of Wholesale Electricity Spot Market Pricing,*" at page 1, by A. Joseph Cavicchi, Executive Vice President, Compass Lexecon, prepared for the Electric Power Supply Association, (issued March 31, 2014) ("Cavicchi Paper").

and power producers.[19] Further, artificially low prices in the short term may result in higher or volatile price formation over the longer term.

At the April 1 conference, Chairman LaFleur rightfully raised concern over the reliance on uplift payments this winter.

> We saw obviously some very, very high prices this winter but I am very interested in probing how much of that was reflected in the actual, you know, marginal market price, the LMP, versus Uplift or extraordinary or out-of-market prices. Because the market prices are supposed to be sending a signal, not just for who to run in the short term or tomorrow, but what kind of investment decisions or maintenance decisions or staffing decisions, and even fuel supply decisions, people in the market are making.[20]

In response, Michael J. Kormos, Executive Vice President – Operations, of PJM noted,

> I think that's probably one of our biggest issues going forward is, as you said Commissioner, we don't want [gas costs] in Uplift. We need it into the marginal prices, and that is where we preferred it. We have a lot of efforts going on right now to try to minimize our Uplift payments.[21]

At this time, certain ISOs/RTOs are addressing the uplift issues through stakeholder processes.[22] EPSA urges those efforts to continue expeditiously, with an

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19 See attached Cavicchi Paper for extensive discussion of uplift and its impacts to the market.

20 April 1 Technical Conference Transcript, page 111, lines 24-25; page 112, lines 1-8.

21 April 1 Technical Conference Transcript, page 113, line 25; page 114, lines 1-4.

22 *See* ISO New England ("ISO-NE") Net Commitment Period Compensation ("NCPC") project, which is aligned with the ISO's Energy Market Offer Flexibility project, NEPOOL Committee materials and ISO-NE filings and orders are available here http://www.iso-ne.com/key_projects/index.html; additionally, ISO-NE began a series of Price Formation Technical seminars in February 2014 with meetings scheduled through September 2014 to consider pricing issues and evaluate potential alternatives, including ELMP, (Presentation of Ronald Coutu, Strategic Market Advisor, ISO-NE, at CAISO Pricing Forum, April 22, 2014 at Slides 2 and 12., see fn. 14); *Also see* PJM Energy Market Uplift Senior Task Force ("EMUSTF"), details available here http://www.pjm.com/committees-and-groups/task-forces/emustf.aspx; *and* PJM presentation from December 20, 2013 EMUSTF Meeting, *"Uplift in Other RTOs,"* available here http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02a-uplift-in-other-rtos-presentation.ashx.

eye towards resolution in the short term. However, stakeholder processes sometimes become bogged down and take too much time. Therefore, Commission directions and deadlines are essential in identifying for ISOs/RTOs and stakeholders those reforms that require timely and efficient attention in order to make critical repairs. And, as noted above, five RTOs recently met for the California ISO Market Pricing Forum to discuss and share concerns over forward and real time price formation. EPSA supports these efforts, and will work with ISOs/RTOs in this and other venues to address these issues. However, EPSA also urges the Commission to take action to ensure that these efforts continue, with results. For instance, EPSA suggests that the Commission require each ISO/RTO to study uplift and identify trends and causes, as well as identify measures that can be taken to reduce occurrences of uplift and improve transparency around uplift causation and resolution. Each ISO/RTO should file its findings with the Commission in this docket within 60 days. Such studies will have value by highlighting possible reforms by market, and ensuring an open dialogue between each regional market and the Commission, while holding ISOs/RTOs accountable for their market performance.

The key is to take action now, as these issues are pressing and impact both operational and investment decisions being made today as to next winter and those beyond it. As Mr. Cavicchi explains,

> Efficient price signals will provide incentives to sellers to be available and operational in the short run (including supporting fuel procurement decisions) and ensure that economic resources do not prematurely retire as a result of suppressed energy prices....Although it can be difficult to define precisely the most efficient rules for improving the price setting process, additional progress is required to ensure that uplift payments are not utilized in lieu of competitive spot market prices that truly reflect all costs.[23]

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[23] Cavicchi Paper at page 7.

B. Offer Caps

As was clearly demonstrated by emergency tariff waiver requests submitted this winter from both PJM and the New York ISO,[24] current price and offer caps of $1,000/MWh are no longer just and reasonable based on changes in conditions since the Commission approved them many years ago. Thus, these caps prevent wholesale markets from setting efficient electricity prices in certain ISOs/RTOs. Although the emergency offer cap waivers the Commission granted ensured that resources would be adequately compensated when costs exceeded historical offer caps <u>after</u> the Commission approved them – and importantly gave generators confidence that going forward this past winter they would recover costs incurred – those temporary fixes were just that, temporary. The opportunity must be taken now to address this market design flaw so that a resolution will be in place before another emergency event or events occur again. Put simply, this issue cannot be addressed year by year, or season by season, by individual waivers without negative repercussions. In the absence of a permanent resolution, generators will likely not have sufficient confidence that they will have a fair opportunity in ISO/RTO markets to recover costs incurred to serve the system.[25] The approval of future waivers cannot be assumed, nor can generators assume that they would be approved in a timely manner before damage is done, as happened this winter before the waivers were sought and granted. As a general

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[24] *See, generally*, PJM Interconnection, L.L.C., 146 FERC ¶ 61,078 (2014) ("PJM Waiver Order"), and New York Independent System Operator, Inc., 146 FERC ¶ 61,061 (2014) ("NYISO Waiver Order").

[25] *See e.g.* Complaint of Duke Energy Corporation On Behalf of Duke Energy Commercial Asset Management, Inc. and Duke Energy Lee II, LLC Against PJM Interconnection, LLC and PJM Settlement, Inc., Or, In The Alternative, Request For Waiver, Docket No. EL14-45-000 (filed May 5, 2014) ("Duke Gas Cost Recovery Complaint").

principle, if generators cannot be confident of a fair opportunity to recover their costs, they will be forced to make decisions that may detrimentally impact future reliability, such as not being able to procure expensive fuel needed to operate.

As explained in greater detail in the attached policy paper, the market rules must be changed to: (1) permanently revise now clearly out-of-date offer and price cap tariff rules to ensure that market offers (and therefore market clearing prices) reflect unexpected short-run marginal cost increases; and, (2) ensure rules are sufficiently flexible to allow buyers and sellers to make decisions based on offers that reflect actual real-time market conditions. The original purpose of the offer caps, such as those put in place in PJM in 1997 and NYISO in 2000, was to act as a blunt instrument to address seller market power concerns. However, much has changed in the intervening years. For example, the Commission has substantially strengthened how it administers its market-based rate authority program, as acknowledged in several court cases, including through the use of market power screens as part of the triennial review of market participants eligible for the program.[26] Furthermore, the U.S. Congress through the Energy Policy Act of 2005 gave the Commission enhanced enforcement tools including authority to seek civil penalties of as much as $1 million per violation per day. Unlike when the arbitrary and inflexible offer caps were put in place years ago, the Commission now has a well-staffed Office of Enforcement with experts from a variety of disciplines, expanded analytical tools including real time market monitoring, and greater

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[26] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified* 121 FERC ¶ 61,260 (2007) *order on reh'g*, Order No 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No.697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Montana Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), cert denied, 133 S. Ct 26 (2012).

access to other information such as through the recent Memorandum of Understanding with the Commodity Futures Trading Commission. Thus, the offer caps are no longer necessary to provide the intended consumer protection from any use of seller market power. As data on historic wholesale prices for each ISO/RTO amply demonstrates, such prices are almost always a small fraction of the $1,000/MWh offer cap and so the cap in normal times has no effect. Rather, the offer caps artificially suppress market prices and prevent economic outcomes that will support reliability precisely under stressed conditions such as the extreme weather this past winter. Thus, not only are the existing caps unnecessary, they are counter-productive as evidenced by this past winter.

The Commission and the ISOs/RTOs have several options to consider with input from all stakeholders – remove the existing offer caps, raise them to a sufficient numerical dollar level that will allow greater room for actual operating costs, or devise an alternative floating cap based on a reasonable index that allows for sufficient market opportunity to recover production costs. Any cap should apply equally to all resources – supply and demand response.[27] Mr. Cavicchi documents the economic justification for such changes based on the uniform clearing price auction that the Commission has approved as the foundation of centralized electricity spot market design.[28]

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[27] April 1 Technical Conference Transcript, page 95, lines 18-22. (Michael J. Kormos, PJM Executive Vice President – Operations, conference statement reflects the different offer price caps between Generation and DR in PJM: "The problem is, we've committed to cover that peak. So we've committed an additional 3,000 either in Demand Response at most likely $1,800, or gas-fired generation at $1,000-plus to cover that, which is now going to end up going into Uplift because it is not needed.").

[28] *Commonwealth Edison Co.*, 113 FERC ¶ 61,278 at P 43 (2005), "[T]his pricing methodology is known as the 'single clearing price' method and has the benefit of encouraging all sellers to place bids that reflect their actual marginal opportunity costs. . . . The single price method has been proposed and found to produce just and reasonable rates for all the energy and ancillary service markets currently

Mr. Cavicchi explains,

> Important benefits flow from efficient spot market prices. By revealing to sellers the actual value of energy production, sellers are provided the best incentives to be available, to operate reliably, and to enter into forward market sales contracts. At the same time, by revealing to buyers the actual value of consumption of spot market energy, buyers will be less likely to rely on the spot market and seek to shift costs onto others, and be more likely to enter into forward market hedges. Moreover, by setting efficient spot market prices, the spot market design guides medium and longer-term power purchase and sale decisions that tend toward more optimal resource allocation.[29]

The Commission has correctly acknowledged the validity of this fundamental economic principle, stating in its order approving PJM's emergency tariff waiver that, "By limiting legitimate, cost-based bids to no more than $1,000/MWh, the market produces artificially suppressed market prices and inefficient resource selection."[30] Further, the Commission has for years consistently and for good reasons stated "[p]ayments made

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operated by the independent system operators and regional transmission organizations under our jurisdiction."

Order No. 755, Frequency Regulation Compensation In The Organized Wholesale Power Markets, 137 FERC ¶ 61,064 at P 99 (2011), "The Commission finds that paying to all cleared frequency regulation resources a uniform clearing price that includes the marginal resource's opportunity costs is just and reasonable. Accordingly, this Final Rule requires that all RTOs and ISOs with centrally-procured frequency regulation resources must provide for such opportunity costs in their tariffs. Further, this uniform clearing price must be market-based, derived from market-participant bids for the provision of frequency regulation capacity. As commenters recognize, contrary market pricing rules would consistently result in artificial and inaccurate prices that do not include the total cost of reserving regulation capacity. In addition, paying an out-of-market unit-specific opportunity cost, rather than a uniform clearing price, can result in the market basing the commitment of regulating units on bids that do not reflect the true cost of providing capacity, potentially leading to committing units with higher costs than other units not committed. By not paying a uniform clearing price, it is possible, for instance, to dispatch a unit with relatively low explicit capacity costs but very high opportunity costs, rather than a lower-cost unit which has relatively higher explicit capacity costs but low opportunity costs. This can result in distorted investment and entry decisions by market participants. Paying to all cleared frequency regulation resources a uniform price that includes opportunity costs will ensure that all appropriate costs are considered and will send an efficient price signal to current and potential market participants. This will also be consistent with long-standing Commission policy approving uniform clearing prices [FN 158]."

[29] Cavicchi Paper at page 9.

[30] PJM Waiver Order at P 40.

only to individual resources and recovered in uplift fail to send clear market signals," and that those resource costs "should be reflected in transparent market prices whenever possible."[31] The Commission could not have said it any better. Having again reaffirmed the validity of this approach in the waivers granted this past winter, the Commission has an obligation to apply it more broadly going forward so efficient market outcomes are not dependent on future after-the-fact waivers. This economic rationale must be more than a mere talking point, it must be a guiding principle in the evaluation of how to address energy market offer caps (and price formation generally).

As explained in an affidavit submitted by EPSA in the PJM Waiver proceeding by Dr. Susan Leise Pope, Managing Director of FTI Consulting,[32] market prices are set based on the cost of generation of the marginal unit that clears the market. Doing so provides an efficient price signal for both the short term (Day Ahead and Real Time economic dispatch by the RTO) and the long term (investment decisions for existing and new generation resources).[33] Such a signal is required at all times, but may well

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[31] *PJM Interconnection, LLC*, 139 FERC ¶ 61,057, at P 78, n.72. *See also* Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, III FERC Stats. & Regs. ¶ 31,281, at P 192 (2008), as amended, 126 FERC ¶ 61,251, order on reh'g, Order No. 719-A, III FERC Stats. & Regs. ¶ 31,292, reh'g denied, Order No. 719-B, 129 FERC ¶ 61,252 (2009) (Order No. 719) ("existing rules that do not allow for prices to rise sufficiently during an operating reserve shortage to allow supply to meet demand are unjust, unreasonable, and may be unduly discriminatory. In particular, they may not produce prices that accurately reflect the value of energy and, by failing to do so, may harm reliability, inhibit demand response, deter entry of demand response and generation resources, and thwart innovation"); *see also*, California Independent System Operator, Corp., 141 FERC ¶ 61,069, at P 44 (2012) ("we note that we are concerned with the extent of CAISO's reliance on out-of-market solutions, which tend to artificially depress market prices. It is important for the CASIO markets to have prices that accurately reflect the market value to operate certain resources so that the market will accurately communicate through the locational pricing model where the new transmission and generation are needed").

[32] *Comments and Affidavit of the Electric Power Supply Association*, Docket No. ER14-1145-000 (filed Jan. 30, 2014), Exhibit 1, Affidavit of Susan Liese Pope, Managing Director of FTI, Inc. ("Pope Affidavit").

[33] "If the market is competitive... then the clearing-price auction has two wonderful properties. The first is short-run efficiency. The dispatch of generation throughout the day is efficient—the electricity is generated at least-cost to the system, since all generation is supplied by the producers with the lowest

be most pressing to reflect conditions such as the high natural gas prices seen during the extreme weather this winter. PJM recognized this fundamental market principle, as it explains in its emergency waiver filing.

> That principle—basing clearing prices on the costs of cleared sell offers—is fundamental to PJM's energy market design, and that principle should not be set aside, even for an interim period. To the contrary, it is especially critical to honor that principle at the very times, such as experienced this winter, when seller costs are high. There is no question that fuel costs are a legitimate marginal cost of generation, and there also is no question that generators that have had to purchase natural gas on the spot market this winter have at times faced extremely high costs for that gas. Consequently, there is no sound basis for energy prices to ignore those costs.[34] (emphasis added)

Dr. Pope further explains,

> PJM is able to achieve the economic efficiencies of least-cost dispatch when it receives offers from suppliers that reflect their marginal costs. And, as predicted by theory and shown by experience, the most reliable way to elicit marginal cost-based offers from sellers is to pay them market clearing prices. *Provided that a competitive supplier is paid the market clearing price*, it will maximize its profits by setting its offer for each unit of output above minimum load equal to its actual marginal cost of production. Efficient pricing lies at the heart of the design of competitive energy markets based on economic dispatch and LMP, like that in PJM.[35]

To disallow offers that reflect marginal costs which may be above the current $1,000/MWh cap would result in a host of short-run and long-run inefficiencies, as detailed by Dr. Pope in her affidavit in Docket No. ER14-1145-000.[36]

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cost. The second is long-run efficiency. The single clearing-price auction motivates efficient investment in new generation." Peter Cramton, *"Foreword to Ross Baldick's 'Single Clearing Price in Electricity Markets'"* prepared for the COMPETE Coalition, www.competecoalition.com, (Feb. 2009), *Available at*: http://works.bepress.com/cramton/157.

34 PJM Waiver Filing at pages 3-4.

35 Pope Affidavit at page 3 (notes omitted).

36 Pope Affidavit at pages 6 – 10 generally.

Of note, the energy pricing problems experienced in the California ISO ("CAISO") this winter are related to this broader issue, but represent a particular dilemma apparently unique to California. In CAISO, the problem was one of not letting generators reflect their actual cost of fuel in Day Ahead bids, due to the requirement to use a natural gas price index which lags 24-48 hours behind the intraday purchase price. This generally does not create a problem because natural gas prices are usually relatively stable over this short time horizon. However, as became painfully evident this past winter, the CAISO method poses a particular difficulty during extreme weather events characterized by high short run natural gas price volatility. This situation is compounded when the ISO directs same-day Exceptional Dispatch, requiring intraday fuel purchases during such volatile natural gas market conditions by those generators so dispatched. This winter, CAISO filed for an emergency waiver with the Commission to seek some modest level of temporary cost recovery for generators. Many market participants raised concerns that the waiver as granted by the Commission was insufficient to ensure reasonable cost recovery. Based on the lessons learned from winter 2013-2014, the Commission should require CAISO to address this critical issue before next winter to ensure Day Ahead bids are allowed to reflect accurate fuel costs so that generators are not penalized for taking steps to reliably meet consumer demand particularly during extreme weather conditions.

While the very high natural gas prices across the country this past winter were not forecasted, they are a reasonable and legitimate production cost of the marginal unit that should be reflected in LMPs when such natural gas costs do occur. While the offer cap issue emerged only this past winter when it became binding, EPSA's serious concerns about flaws in energy market price formation under current rules and practices predate the recent extreme weather conditions, but were evidenced by the market problems experienced this winter. Further, as stated at the April 1 conference by numerous panelists, the recent extreme weather events and their consequences for energy markets are but part of the broader concern that unnecessary artificial constraints on wholesale markets have serious adverse consequences when flexibility is needed most. Within that list of needed market reforms, reviewing and revising the current energy market offer cap mechanisms should be undertaken as soon as practicable to prevent recurrences and offer market participants the confidence that prices will reasonably reflect market conditions, particularly in times of system stress when by definition supply resources are needed most.

C. Intraday Offer Opportunities

Closely associated with eliminating or revising offer and price limitations based on out-of-date price caps is the need to offer intraday flexibility for market participants to adjust offers as appropriate to reflect rapidly changing market conditions. Reflecting actual market conditions, including unexpected fuel price volatility or system constraints, is necessary to reduce sellers' uncertainty regarding adequate compensation when they run and to support ongoing operational and capital investment decisions. Additionally, this intraday or hourly flexibility will benefit the interaction of the gas and electric markets by allowing power offers to adjust to gas price variation between day-ahead and real-time scheduling and delivery times, as well as oil price variation for dual fuel units which were relied upon heavily in several markets this winter.

Currently, with the Commission's approval, NYISO provides the necessary flexibility to modify real time offers in order to reflect actual fuel prices when such prices vary from day ahead levels. This precedent should form the basis for improvements in other ISOs/RTOs. Though this important market feature was hampered temporarily in New York by the $1,000/MWh offer cap, which was resolved with a cost of service tariff waiver, the ability to submit hourly reoffers that reflect changing fuel costs is essential to reflect the market cost of electricity. This is particularly important during critical periods when the real time system dispatch does not match the day ahead schedule, which can be due to a number of factors, both internal and external to the ISO/RTO. During these periods, suppliers need to be assured that they will be fully compensated for performing according to ISO/RTO dispatch directives. Mr. Cavicchi notes,

> Providing offer flexibility that allows hourly differentiation of day-ahead and real-time offers reduces financial risks faced by sellers and provides an ISO with greater assurance that sellers will have an incentive to follow commitment and dispatch awards. The ability to incorporate gas price variation between the day-ahead and real-time spot markets will improve ISO commitment and dispatch decisions (e.g., less uncertainty regarding cost recovery will allow more accurate bids which should improve commitment and dispatch). In addition, in instances where seller resources have dual-fuel capability, improved flexibility should provide better signals for fuel switching decisions. Moreover, offer flexibility results in spot market prices that better reflect actual fuel supply costs[].[37]

EPSA urges that all RTOs be required to provide additional offer flexibility – optimally hourly reoffer opportunities – in order to address both short run operational issues, as well as ensuring that market participants have confidence in their ability to recover costs and make investment decisions supporting their generation resources.

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[37] Cavicchi Paper at page 12.

An example of a short run operational issue that would be supported by greater offer flexibility is allowing generators to submit intraday offers which reflect either a change in price for various fuels or an operational need to switch fuels during a critical period of the delivery day. Both FERC staff and several of the RTO representatives highlighted the increased reliance on dual fuel generation or back up oil generation during critical periods this winter due to both inter-fuel price differences in some instances and the unavailability of natural gas in others. However, switching fuel on an intraday basis can be stymied by limitations on intraday offer opportunities. Therefore, to support the utilization of dual fuel units during emergency or tight situations, units need the flexibility to submit offers which allow them to switch fuels during the delivery day and set the clearing price based on the fuel utilized. Currently this ability to switch fuels intraday is hampered because generators have no means of showing the market an updated price demonstrating that the secondary fuel is more cost effective.

The need for intraday fuel switching from gas to liquid fuel, or vice versa, can be based on directives from the RTO in order to meet unexpected peaks, changing price differentials between fuels, or the loss of access to the generator's primary fuel. Therefore, to allow a unit to remain on-line and available to the market, even should they lose access to their primary fuel, intraday offer opportunities are necessary. This will help ensure the system is as reliable and flexible as possible based on rapidly changing market factors and operational circumstances.

D. Coordination of Electric and Gas Day Scheduling

Greater coordination of the electric and natural gas systems is needed, and is currently under consideration and deliberation by the natural gas and electric industries.

As FERC has found in its timely NOPR on this issue,[38] requirements and obligations from the Day Ahead electric market should be known in time for generators to then make gas supply and transportation arrangements while the natural gas markets are liquid so that generators have many fuel supply and delivery options to meet their needs. However, doing so is complicated by vast differences between the operations and schedules of the electric and natural gas industries. In order to navigate the issue, the Commission has set up a separate proceeding which includes a set of proposals, but also allows industry a period of time to develop a consensus alternative proposal if possible. EPSA is actively participating in that proceeding,[39] and applauds the Commission for leaving room for stakeholder dialogue while exerting pressure that action must be forthcoming by a date certain either based on stakeholder consensus, or barring that consensus, through potential Commission action without it. It is just such a public action-forcing approach that EPSA believes is also necessary to achieve

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[38] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 146 FERC ¶ 61,201, Docket No. RM14-2-000, at PP 52-53, (issued March 20, 2014) ("Scheduling NOPR"), ("...Under our proposal, gas-fired generators would have the option of arranging natural gas supply and transportation at the Timely Nomination Cycle knowing the results of the day-ahead electric market. In particular, this would forward the objective of minimizing situations in which gas-fired generators, particularly those that opt to procure natural gas supply and transportation after the day-ahead electric market results are posted, are unable to procure sufficient resources to fulfill their electric market commitments and to contribute to reliable system operation. 53. Furthermore, as discussed above, a gas-fired generator's inability to know whether its bid in the day-ahead market has been selected prior to the deadline for the Timely Nomination Cycle may lead to instances in which gas-fired generators must sell off excess natural gas supply, procure more expensive natural gas supply, de-rate, or burn more expensive fuels. We are concerned that any of these scenarios could result in increased electricity costs and a shift away from the least-cost mix of supply resources as determined by the ISO or RTO's day-ahead dispatch and unit commitment. These circumstances could lead to higher costs being passed on to wholesale customers...").

[39] The Scheduling NOPR provides time for the natural gas and electric industries to reach consensus that might differ from the NOPR's proposed revisions through the North American Energy Standards Board ("NAESB") process. That process must conclude by September 29, 2014, and the NAESB committee established for this effort is the NAESB Gas-Electric Harmonization Forum ("NAESB GEH Forum"). Additional information is available here http://www.naesb.org/committee_activities.asp.

meaningful improvements in the energy, capacity and ancillary services markets on a timely basis as discussed elsewhere in these comments.

Additionally, an important piece of the solution will be how the ISO/RTO markets conform to changes in the natural gas industry. The development of conforming offer and commitment timelines for wholesale power markets may be a challenge as each RTO currently utilizes its own timeline (and they all differ from one another). It may be possible that, particularly if the Gas Day is moved to an earlier time in the morning, the ISOs/RTOs will need to implement different bidding schedules than each utilizes at present. While there may not be one perfect scenario that will please every RTO, there will be vast benefits if the electric and natural gas days sync with each other to a much greater extent.[40] Therefore, EPSA urges each RTO to remain open to power market timeline changes that will best conform to any changes on the natural gas side to realize the full benefits of revised natural gas and electric time schedules. This discussion and debate, however, will occur after the issuance of a Final Rule on the Gas Day and nomination schedule, likely late this coming winter.

An issue of concern this past winter and raised at the April 1 conference is generators having to procure natural gas on Friday for the coming three days over the weekend (including Monday) priced as a package, and sometimes for four days over a holiday weekend. There should be solutions to this problem that can be pursued by the Commission and market participants. For instance, the development of products on trading platforms and price indices for the traditional Saturday/Sunday weekend days

[40] *See e.g.* Duke Gas Cost Recovery Complaint at pages 13-23 (reflecting the impacts of the electric and gas day misalignment during the extreme winter weather of January 2014).

separate from the different demand conditions on a typical Monday could bring greater price transparency and divergence between Saturday/Sunday and Monday, and in fact might support the development of a more liquid daily market over the weekend (or for individual weekend days).

Finally, though the Commission did issue Order No. 787 to improve communication and information sharing between natural gas pipelines and the electric industry,[41] care is needed to ensure that generators are included in any communications that take place regarding their own operational situation. EPSA members report several circumstances in which individual generators were dispatched based on inaccurate or incomplete sharing of information between the pipeline and the generator's ISO/RTO about the generator's own operations. For instance, as detailed by Abraham Silverman of NRG at the April 1 conference,[42] in one situation inaccurate information was exchanged about a generator's available gas supply and transportation, leading the unit to be curtailed even though adequate gas had been procured. This situation was compounded when the unit was called back online after its gas supply was sold in order to manage imbalance penalties with the pipeline. Had the generator been involved in the communications between the ISO and the pipeline, this expensive and inefficient result could have been avoided. Instead, the generator could have provided the most accurate and up-to-date information about its own gas supplies. Therefore, EPSA

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[41] *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, Order No. 787, 145 FERC ¶ 61,134, (November 2013).

[42] Panel 2: Stakeholders Discussion - Abraham Silverman, Assistant General Counsel – Regulatory, NRG presentation, 2013/14 Cold Weather Operations, FERC Technical Conference, Docket No. AD14-8-000, (April 1, 2014), page 13, *Available here* http://www.ferc.gov/CalendarFiles/20140401084620-Silverman,%20NRG.pdf.

requests that FERC issue a clarification to Order No. 787 that requires that the generator's 24-hour real-time desk be a part of any communication between the ISO/RTO and the pipeline that involves its gas or operating status. And if real-time conditions do not allow for three-party communication (which seems unlikely with today's technology), then the ISO/RTO should immediately be required to notify the generator of the information it learned, and then correct any inaccuracies.

III. CONCLUSION

WHEREFORE, EPSA respectfully requests swift adoption of the reforms and clarifications discussed in these comments in order to ensure that prices will efficiently signal the appropriate investment necessary to ensure continued reliability of the electric system. This is especially important to achieve soon given that investment decisions informed by price signals are being made on an ongoing basis. To that end, EPSA strongly urges the Commission to establish expeditious timelines for appropriate action by the Commission and the ISOs/RTOs for each of the wholesale market issues discussed herein.

Respectfully submitted,

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ATTACHMENT A

Organized Wholesale Markets Require Meaningful Reforms In Light Of Serious Challenges

Presentation by:

Electric Power Supply Association
January 2014

Organized Wholesale Markets Require Meaningful Reforms In Light Of Serious Challenges

Electric Power Supply Association

January 2014

Overview: Why Timely RTO Market Reforms Are Needed

- EPSA supports well-functioning competitive wholesale markets that are economically sustainable to continue providing long-term benefits to consumers
- Reliability in competitive wholesale markets hinges on whether, when and how private capital is invested in existing and new resources; such decisions are being made today that will impact reliability later this decade and beyond
- Investment decisions in organized markets are in significant part made on the basis of long term total cumulative revenue adequacy from energy, capacity and ancillary services markets, which hinges on market design, tariffs and grid operator practices for each RTO and ISO, often the result of past compromises
- Present market design and tariffs do not fully reflect significant structural changes and market conditions that have occurred, are underway, or are expected since present design and tariffs were approved; the impacts of this mismatch are aggravated by certain grid operator practices that undermine market integrity
- Given structural changes, not merely cyclical fluctuations, FERC should focus on long term reliability and therefore should pursue timely RTO market reforms
    - Capacity Markets – not only continue current FERC review of Eastern RTO/ISO markets, but then develop best practices based on public input and require RTOs/ISOs to demonstrate how they have or will satisfy them
    - Energy and Ancillary Services Markets – initiate a similar process leading to best practices based on public input and require RTOs/ISOs to show they have or will satisfy them given the role these markets play in investment decisions and acquisition of necessary resources

Significant Changes Since Current Market Designs and Tariffs Were Approved: Does It All Still Add Up?

- Low load growth has become the new normal going forward
- Natural gas prices result in lower energy market revenues
- Increased amount of resources participating in wholesale markets with out of market revenues
- Increased role for variable and distributed resources impacts revenues and costs for other resources needed for reliability
  - Alters the dispatch mix, lowering capacity factors for many types of resources
  - Squeezes energy and capacity revenues for generation needed to backstop variable resources
  - Stresses many existing units through increased need for cycling and ramping
- Federal and state policies will continue to seek environmental improvements
- Evolving effects of new technologies
  - Level of impacts and timing remain key unknown variables
  - FERC should remain technology neutral in developing market rules
  - FERC has critical role in crafting market rules relating to integration of new technologies consistent with competitive markets and system reliability

Early Warning Signs Are Evident and Compelling

- Current and forward price signals are generally weak, the key question for reliability is why
- *If* weak price signals reflect market fundamentals, then economically unsustainable resources are not necessary for reliability; *however, if*, as happens too often, weak price signals also reflect market design flaws and grid operator interventions, resources needed for reliability in the future are at risk
- Retirements were originally driven by environmental costs impacting older, smaller coal units dispatched infrequently; recent retirements include nuclear and larger, newer or upgraded coal units; and some natural gas plants that are needed to provide future system flexibility face retirement sooner
- Early warning signs indicate that regulatory conditions should be examined generically and appropriate RTO market reforms implemented before the investment climate erodes further

Conclusions

- EPSA strongly supports competitive wholesale power markets, which provide significant consumer benefits but require well-functioning updated market designs and tariffs properly implemented through grid operator practices
- As summarized in the attached appendix, RTO improvements should be pursued in five policy areas: (1) energy and ancillary services price formation; (2) capacity markets; (3) out of market entry and uneconomic supply; (4) demand response; and (5) transmission and seams
- How best to pursue RTO/ISO improvements procedurally?
  - FERC "best practices" policy statements based on public input combined with RTO accountability to show how each RTO satisfies them or will change to meet them could achieve timely reforms in a balanced manner
  - Decisions in individual RTO dockets can be effective on discrete issues; rulemakings may be required but the process is lengthy; and while stakeholder processes are important, they can delay necessary reforms that are critical to address given the challenges facing wholesale markets

APPENDIX ON MARKET REFORM ISSUES AND SOLUTIONS

Background: Nature of Competitive Power Model

- Competition shifts risks from consumers to investors, however resource adequacy is not free under any regulatory model

- Investor risks should be accompanied by the *opportunity* to earn revenues sufficient to recover fixed and variable costs plus a reasonable return on invested capital; there are no guarantees in a competitive market, but nor should there be unnecessary barriers created by market-distorting actions

- Restructuring did not result in “deregulation” as was done elsewhere
  - Wholesale markets have prices heavily shaped by FERC-jurisdictional market designs, tariffs, and operator practices, plus market monitor intervention
  - More uplifted/socialized charges distort accurate price discovery
  - Services are being provided without proper compensation (e.g., reserves, reactive power/voltage support)
  - Bias is toward over-mitigation resulting in high-priced peaks being shaved while downside remains

- Just and reasonable outcomes require improved energy, capacity and ancillary services markets as outlined in detail in subsequent slides

RTO Reforms Needed In Five Key Categories

1. Energy Market and Ancillary Services Price Formation
2. Capacity Market and Resource Adequacy Rules
3. Out of Market Entry and Uneconomic Supply
4. Proper Role for Demand Response
5. Transmission and Seams

Energy Market Price Formation
(markets need accurate price signals)

- LMPs must be allowed to fully reflect market conditions
  - RTOs/ISOs fail to price "reliability" commitments (dynamic markets are disrupting former regime of baseload, mid-merit and peaking plants with increasing use of reliability and other non-priced dispatches)
  - MWs put onto grid for reliability need to be factored into LMPS, un-hedgeable uplift should be minimized, and all constraints need to be modeled in the market
  - All operator actions taken to meet marginal demand should be reflected in LMPs regardless of min/max output levels, etc. (Too often multiple units are dispatched at minimum load)
  - After-the-fact review of dispatch actions would better coordinate operations and markets functions
  - Greater transparency regarding dispatch actions and grid conditions
- Many administratively mitigated prices skew true market prices
  - Bids must be allowed to reflect real time costs
  - Reassessment of components of short run marginal costs
  - Additional intra-power day reoffer or bidding opportunities
  - Reliability commitments should be scheduled day ahead and reflected in day ahead LMPs
  - Proper real time prices will lead load to bid more in day ahead and not only real time

Capacity Market and Resource Adequacy Rules

- Capacity market is for physical not financial resources
- Sloped demand curve to better reflect price and reliability
- Forward procurement period should better align with transmission planning time horizon
- Forward commitment should be at least one year (with careful review of pros and cons of non-discriminatory options for longer pricing periods for a portion of capacity)
- Locational value to signal investment in constrained areas
- Seller-side mitigation must allow long-term fixed costs
- Buyer-side mitigation must prevent undue price suppression
- Transparency and tradability should be enhanced
- Capacity imports into RTOs and ISOs should respect physical and operational reliability limits
- More predictable future capacity market prices are desirable

Out of Market Entry and Uneconomic Supply

- RMR resources should be held out of energy and capacity market price calculations to avoid artificially suppressing market prices

- Careful review required to determine the nature, extent and impacts out of market revenues have on accurate price formation

- Strong MOPR and other buyer-side market power rules will continue to be key market design elements

- *Edgar*-like guidelines for utility self-builds may help ensure fair consideration of market options or else rate-based generation within RTOs distort market outcomes

Proper Role for Demand Response

- Demand response has an appropriate role in electricity markets; given the increased level of demand response that is now participating in RTO markets, the issues going forward revolve around comparable regulation if demand response is to receive comparable compensation

- Ideally demand response should be an energy market, not capacity market, product

- If a capacity market product, demand response should have comparable "must offer" obligations and when called in energy markets be factored into LMPs

- Energy market compensation should reflect savings from foregone retail consumption

- If demand response is allowed in the capacity markets:
  - Comparable basis as a single, annual unlimited physical product
  - Behind-the-meter resources should participate as generation, not masquerading as DR
  - No hold-back percentage from base auctions for later ones

Transmission and Seams

- Greater coordination and transparency between neighboring RTOs/non-RTOs are necessary
- Problems largely stem from historically different approaches to assumptions, modeling, and outage coordination as opposed to technical rationales
- Balancing areas should better align transmission and generation outage scheduling across seams
- Operational and physical constraints must be respected
- Interconnection and transmission service queues should be studied at the same calendar intervals
- Basic modeling elements and assumptions should be consistent across RTOs and non-RTO areas