# Technical Committee Conference Call

January 7, 2009 ⚡ 1:30 PM Eastern

Dial-In: **716.517.4400** Meeting ID: **5905**

## TENTATIVE AGENDA

A. Introductions & Antitrust Statement

B. Review & Approve Draft Minutes of December 10, 2008 Conference Call (Attachment 1)

C. Federal Update – Marc Yacker will report on status of President-Elect Obama's transition and energy/climate change matters, related initiatives in proposed economic stimulus bills

D. FERC Update – John Hughes will report on recent actions at FERC on important electricity issues including recent DC Circuit decision on PURPA Section 210m (Attachment 2)

E. Report on Pennsylvania PUC En Banc Hearings on Wholesale Electricity Markets – John Hughes

F. Report on FERC's Third Annual Assessment of Demand Response & Advanced Metering – John Hughes (Attachment 3)

G. Technical Committee Work:

1. Review and approve draft ELCON comments on NAESB standards on demand response – John Hughes (Attachment 4)

2. Discuss proposal on energy efficiency resources in PJM capacity markets and ELCON intervention – John Hughes (Attachment 5)

H. NERC Update – ELCON staff will report on an as-needed basis on any recent activities at NERC of interest to large industrial customers

I. Other Committee or ELCON Business

J. Adjournment

Attachment 1
Draft Dated December 30, 2008

# Minutes of the Technical Committee Conference Call

December 10, 2008 ⚡ 1:30 PM Eastern

A conference call meeting of the ELCON Technical Committee was held on December 10, 2008 beginning at 1:30 PM Eastern time. Members and staff participating on the call were:

| | |
|---|---|
| Rick Bidstrup | Cleary Gottlieb |
| Steve Castracane | Linde |
| Michelle D'Antuono | Oxy |
| Tom Gianneschi | Alcoa |
| Scott Hawley | BP |
| John Hughes | ELCON |
| Dave Meade | Praxair |
| Darren MacDonald | Gerdau Ameristeel |
| Barry McClelland | Honda of America Mfg. Inc. |
| Chip Millican | Eastman |
| Carol Nichols | ExxonMobil |
| Ray Ratheal | Eastman |
| Bob Ritenuti | Dupont |
| Marty Sedler | Intel |
| Mike Woytowich | Honeywell |
| Marc Yacker | ELCON |

A. **Introductions** – Dave Meade (Praxair) chaired the call. After participants identified themselves they were instructed to be mindful of ELCON's Antitrust Guidelines.

B. **Review Draft Minutes of Previous Meetings/Conference Calls** – The draft minutes of the October 15 conference call and October 22 meeting were approved as written. The draft minutes of the November 4 conference call was approved as amended.

C. **Federal Update** – Marc Yacker reviewed the personnel makeup of President-elect Obama's transition teams, energy/environment related appointments to date, and energy-related provisions of any economic stimulus package. He also reported that ELCON would meet with members of the transition team as part of an ad hoc group of organizations that opposed the pricing policies of the organized markets. The meeting was being organized by the Campaign for Fair Electric Rates.

D. **FERC Update** – Rick Bidstrup (Cleary Gottlieb) reviewed the highlights of the most recent ELCON Law Developments monthly.

E. **Committee Work:**

1. **NAESB Standards on Demand Response** – ELCON staff reported on a recent NAESB subcommittee meeting during which draft standards for demand response

were approved without full consideration of ELCON recommendations. The committee agreed that ELCON should condition any further support for the standards on elimination of the substantial deference given to system operators in the standards.

2. **NERC Proposal on Demand Response** – ELCON staff reported on a recent effort at NERC to define in NERC's Functional Model new functions and responsible entities related to demand response. This would be the first step towards making providers of demand response subject to mandatory NERC Reliability Standards and registration in the NERC Compliance Registry. There was agreement that NERC's efforts were counterproductive and would discourage demand response.

3. **NERC Compliance Registration Interpretations** – ELCON staff reviewed two recent appeals by entities that were forced to register in the NERC Compliance Registry. The appeals—one related to retail marketing affiliates and the other related to behind-the-meter generation—have the potential to impact ELCON member risk of multiple NERC registrations.

4. **ELCON Policy Briefs** – ELCON staff reported on the status of the two new ELCON policy briefs on utility energy efficiency programs.

**F. Other ELCON Business –** ELCON staff reviewed efforts to reschedule the February 2009 ELCON Annual Meeting and Workshop in light of the economic crisis.

**G. Adjournment –** There was no other business and the call ended.

# United States Court of Appeals
**FOR THE DISTRICT OF COLUMBIA CIRCUIT**

Argued November 13, 2008 Decided December 23, 2008

No. 07-1328

AMERICAN FOREST AND PAPER ASSOCIATION,
PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION,
RESPONDENT

COGENERATION ASSOCIATION OF CALIFORNIA, ET AL.,
INTERVENORS

On Petition for Review of Orders
of the Federal Energy Regulatory Commission

*Donald J. Sipe* argued the cause for petitioner. With him on the briefs was *Jonathan G. Mermin*.

*Sara D. Schotland* and *Wayne R. Bidstrup* were on the brief for *amicus curiae* Electricity Consumers Resource Council in support of petitioner.

*Robert H. Solomon*, Solicitor, Federal Energy Regulatory Commission, argued the cause for respondent. With him on the brief were *Cynthia A. Marlette*, General Counsel, and *Judith A. Albert*, Senior Attorney.

Before: GARLAND and BROWN, *Circuit Judges*, and WILLIAMS, *Senior Circuit Judge*.

Opinion for the Court filed by *Circuit Judge* BROWN.

BROWN, *Circuit Judge*: Petitioners insist the term "markets" as used in the recent amendment to the Public Utility Regulatory Policies Act ("PURPA") must always denote a competitive market. The Federal Energy Regulatory Commission ("FERC") interprets the word "markets" to encompass both competitive and non-competitive markets. Because FERC's interpretation is reasonable, we deny the petition for review.

## I. Background

Congress enacted PURPA in 1978, 16 U.S.C. § 824a-3, to encourage expansion of alternative energy by requiring utilities to purchase energy from "qualifying facilities" ("QFs"). *Id.* § 824a-3(a); 18 C.F.R. § 292.303(a). FERC was charged with promulgating rules pursuant to PURPA, which imposed certain mandatory "obligations to purchase" — situations in which a utility had to buy energy from a QF. 18 C.F.R. § 292.303(a).

After almost three decades and apparently based on changes in the energy industry, Congress amended PURPA in 2005 creating exceptions to the mandatory purchase obligation. *See* 16 U.S.C. § 824a-3(m). If FERC finds the circumstances specified in section (m)(1) are satisfied, utilities may be relieved of the obligation to purchase energy from a QF. *Id.* § 824a-3(m)(1).

Section 824a-3(m)(1) refers to "markets" several times. In a formal rulemaking, FERC interpreted the term "markets" in subparagraph (m)(1)(A) as encompassing both competitive and non-competitive markets. *See* New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities, 71 Fed. Reg. 64342, 64345 (Nov. 1, 2006) (to be codified at 18 C.F.R. pt. 292) ("Final Rule"). American Forest and Paper Assocation ("AFPA") petitioned for review, arguing FERC's interpretation was unreasonable.

## II. Discussion

This Court analyzes FERC's interpretation under the familiar standard set forth in *Chevron v. NRDC*, 467 U.S. 837 (1984). Under step one, we ask whether the statutory language is ambiguous. *Id.* at 842–43. Under step two, we ask whether the agency's interpretation is reasonable. *Id.* at 843. Section 824a-3(m)(1) is divided into three provisions, creating three distinct exemptions. Under the statute, a utility is exempt if the relevant QF has "nondiscriminatory access" to:

> (A) (i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy; or
>
> (B) (i) transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission

> shall consider, among other factors, evidence of transactions within the relevant market; or
>
> (C) wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in subparagraphs (A) and (B).

16 U.S.C. § 824a-3(m)(1). AFPA challenges FERC's interpretation of the word "markets" in section (A)(ii).

The first step of the *Chevron* analysis is straightforward. When "markets" is used in section (A)(ii), no specification is given as to whether the markets must be competitive or non-competitive. By contrast, the markets described in both (B)(ii) and (C) specifically use the word "competitive." Although (A)(ii) involves other descriptors, such as "wholesale" and "for long-term sales," silence concerning competitiveness in (A)(ii) creates ambiguity. *See Texas Mun. Power Agency v. EPA*, 89 F.3d 858, 869 (D.C. Cir. 1996) ("In view of its silence on the point at issue, we must hold the statute ambiguous."). *See also Chevron*, 467 U.S. at 843 (referring to silence and ambiguity jointly). The reference in subparagraph (C) to "comparable competitive quality" suggests that the markets described in (A) may have some competitive feature, but the language in (C) is not so strong as to alleviate all ambiguity. Particularly here, where markets in other sections of the statute are specifically denoted as "competitive," silence as to competitiveness in (A)(ii) leaves open whether Congress intended a competitiveness requirement in that provision — a prototypical case for an agency's gap-filling role under *Chevron*.

Having completed step one of *Chevron*, the next question is whether FERC's interpretation is reasonable. Several factors reveal that it is. FERC's interpretation is consistent with the maxim that "[w]here Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion." *Russello v. United States*, 464 U.S. 16, 23 (1983). Because the two uses of the term "markets" occur within the same statute — indeed, in neighboring sentences — the use of the descriptor "competitive" in subparagraphs (B) and (C) suggests that no such requirement was meant for subparagraph (A). "[W]hen Congress uses different language in different sections of a statute, it does so intentionally." *Shays v. FEC*, 528 F.3d 914, 934 (D.C. Cir. 2008).

FERC's interpretation — that the markets in (A)(ii) can be competitive or non-competitive — is consistent with the common usage of the word "markets." Indeed, this Court has often referred to non-competitive markets or monopolistic markets. *See, e.g.*, *Columbia Gas Transmission Corp. v. FERC*, 477 F.3d 739, 744 (D.C. Cir. 2007) (referring to "non-competitive markets"); *Tenneco Gas v. FERC*, 969 F.2d 1187, 1199 (D.C. Cir. 1992) (referring to a "monopolistic market" attribute). Black's Law Dictionary defines a market as a "place of commercial activity in which goods or services are bought and sold." BLACK'S LAW DICTIONARY 988 (8th ed. 2004). Notably, this definition has no requirement that a market be competitive. *See also* WEBSTER'S II NEW COLLEGE DICTIONARY 686 (3d ed. 2005) (defining "market" as "a place where goods are offered for sale"). As the Supreme Court has said, "the words of statutes . . . should be interpreted where possible in their ordinary, everyday senses." *Malat v. Riddell*, 383 U.S. 569, 571 (1966). A "market," in the everyday sense of the word, can be either competitive or non-competitive.

For its part, AFPA cites several cases which refer specifically to "competitive markets." *See, e.g.*, *Consumers*

*Energy Co. v. FERC*, 367 F.3d 915, 922 (D.C. Cir. 2004), *La. Energy & Power Auth. v. FERC*, 141 F.3d 364, 365 (D.C. Cir. 1998), *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 870 (D.C. Cir. 1993) (all using the phrase "competitive market"). AFPA cites these cases in order to advance its argument that courts have consistently required markets to be competitive under the Federal Power Act. This argument is flawed for several reasons: First, the mere usage of the adjective "competitive" in front of the noun "market" does not mean all markets must be competitive; it only shows the particular market in question was determined to be competitive. Indeed, the modifier actually suggests *not all* markets are competitive — hence the need to describe competitive markets as such. Second, as cited earlier, it is equally easy to find cases which use the phrase "non-competitive markets." The fact that courts use both forms shows that the word "markets," by itself, says nothing about competition. Finally, AFPA only cites to usage by courts; none of the cases cited by AFPA deals with use of the word "markets" in a statute.

Another factor supporting the reasonableness of FERC's interpretation is the structure of subparagraph (A) itself. To meet the exemption under subparagraph (A), the utility must satisfy two clauses: (A)(i) and (A)(ii). The first clause, (A)(i), requires "independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy." 16 U.S.C. § 824a-3(m)(1)(A)(i). The parties agree the requirements built into (A)(i) contain an inherent level of competitiveness. Because (A)(i) requires the markets to be "independently administered" and "auction-based," there is some element of competition. On FERC's view, the inherently competitive features in (A)(i) were enough for Congress; no extra requirement of competitiveness was needed in (A)(ii). In other words, independent administration and auction-based sales provide sufficient indicia of competition. Of course, we need not decide the correctness of this question — only that FERC's interpretation was reasonable. It was.

The parties dispute the significance of subparagraph (C), which refers to markets "of comparable competitive quality as markets described in subparagraphs (A) and (B)." *Id.* § 824a-3(m)(1)(C). FERC argues the reference to "comparable competitive quality" refers only to the fact that both subparagraphs (A) and (B) have competitive features — (A) by virtue of the features described in clause (A)(i) and (B) by virtue of the explicit requirement of "competitiveness." AFPA, on the other hand, insists the language in subparagraph (C) requires an *equal* level of competitiveness in (A) and (B). On its view, the potentially lower level of competitiveness created by the features in (A)(i) does not suffice.

As AFPA recognizes in its brief, subparagraph (C) is "not . . . a masterpiece of legislative draftmanship." Pet'r's Br. 42. Because of the lack of clarity in subparagraph (C), we believe both FERC and AFPA present reasonable interpretations. Step two of *Chevron* does not require the best interpretation, only a reasonable one. Given that the features described in (A)(i) contain an inherent level of competitiveness, it is sensible to read the language in (C) as referencing back to the (A)(i) features without inserting a competitiveness requirement into (A)(ii) where Congress did not include it.

Also unpersuasive is AFPA's argument relating to § 824a-3(m)(3), which requires a "factual basis" for utilities to qualify under subparagraphs (A), (B), or (C). 16 U.S.C. § 824a-3(m)(3). AFPA argues that, without a requirement of competitiveness in (A)(ii), the factual basis requirement is a nullity. Of course, this argument ignores the other features required under subparagraph (A). But more importantly, AFPA's concern is answered by the system of review enacted by

FERC. The determinations made by FERC in its final rule are merely rebuttable presumptions. Final Rule, 71 Fed. Reg. at 64343–44; 18 C.F.R. §§ 292.309(c), (d), and (e). After utilities submit information to FERC relevant to an exemption from the mandatory purchase obligation, a QF may rebut the presumption by showing, for example, that it lacks non-discriminatory access to the market in question. 18 C.F.R. § 292.309(e). The fact that FERC chose to adopt certain rebuttable presumptions via rulemaking, rather than by case-by-case adjudication, does not violate any of the statute's requirements. And, as we have long held in such scenarios, the "decision whether to proceed by rulemaking or adjudication lies within the [agency's] discretion." *N.Y. State Comm'n on Cable Television v. FCC*, 749 F.2d 804, 815 (D.C. Cir. 1984). *See also NLRB v. Bell Aerospace Co.*, 416 U.S. 267, 294 (1974).

Finally, AFPA asserts that, lacking a requirement of competitiveness in (A)(ii), QFs will be subject to rates not meeting the "just and reasonable" requirements of 16 U.S.C. § 824d(a). However, any rates that may result from § 824a-3(m) are not presently before us. If and when utilities set rates which any particular QF considers unjust or unreasonable, that QF can file an action under § 824d(a).

For these reasons, we conclude FERC's interpretation of the term "markets" in 16 U.S.C. § 824a-3(m)(1)(A)(ii) was reasonable. The petition for review is denied.

*So ordered.*

Attachment 3

# 2008

# Assessment of

# Demand Response and Advanced Metering

# Staff Report

## Federal Energy Regulatory Commission

**December 2008**

# Executive Summary

Both advanced metering penetration and potential peak load reduction from demand response have increased since 2006. Significant activity to promote demand response or to remove barriers to demand response occurred at the state, federal, and company level.

## Advanced Metering

The results of the 2008 FERC Demand Response and Advanced Metering Survey (2008 FERC Survey) indicate advanced metering penetration (*i.e.*, the ratio of advanced meters to all installed meters) has reached about 4.7 percent for the United States. This is a significant increase from 2006, when advanced metering penetration was less than one percent.

Market penetration of advanced metering increased substantially in nearly all regions since 2006. Peninsular Florida had the largest increase, from less than one percent advanced metering penetration in 2006 to 10.4 percent in 2008.

Market penetration differs by type of organization. While cooperatives, municipal utilities, investor-owned utilities, public utility districts, and federal utilities all show increases since 2006, the high penetration levels achieved by cooperatives in the past two years is particularly impressive. Cooperatives' advanced metering penetration increased from 3.8 percent in 2006 to 16.4 percent in 2008.

## Demand Response Programs

The 2008 FERC Survey indicates that about eight percent of customers in the United States are in some kind of demand response program. There have also been large increases in customer enrollment and the number of entities that offer demand response programs; for example, the number of entities offering real-time pricing increased significantly since 2006.

The potential demand response resource contribution from all U.S. demand response programs is estimated to be close to 41,000 MW, or about 5.8 percent of U.S. peak demands. This represents an increase of about 3,400 MW from the 2006 estimate. The regions of the country with the largest demand response resource contributions as a percent of the national total are the Mid-Atlantic, Midwestern, and Southeastern United States.

## Demand Response Developments

In the past year, several states such as Colorado, Maryland, and Ohio promoted demand response through legislation and utility regulation. Other states, such as Alabama and California, approved time-based rates for customers under their jurisdiction. In addition, multi-state groups spanning the country from the Mid-Atlantic to the Midwest and Pacific Northwest continue to coordinate across jurisdictions to enhance demand response through research, education, and planning.

Numerous utilities and demand response aggregators have taken action to expand their retail demand response programs.  Utilities across the nation are expanding demand-side management programs in response to high load growth and the increasing cost and time required to bring new generation into service.  In addition, third-party demand response aggregators have expanded efforts to include customers who would otherwise be unable to participate in demand response programs.

The Federal Energy Regulatory Commission (FERC) is working to ensure the comparable treatment of demand response resources in wholesale markets.  For example, in October 2008, the FERC issued a final rule on competition in organized markets that, in part, removes several barriers to demand response participation in the organized wholesale markets.  Among other provisions, it requires all regional transmission organizations (RTOs) and independent system operators (ISOs) under FERC's jurisdiction to allow comparable treatment of demand response resources in ancillary services markets, eliminate certain charges to buyers for reducing load during a system emergency, permit demand response aggregators to bid demand response on behalf of retail customers directly into the organized energy market, and change the pricing rules as necessary to allow the market price of power to reflect the value of lost load during an operating reserve shortage.

Demand response resources played a critical role in ensuring the reliability of the electricity grid during periods of severe strain in the past year.  Demand response resources helped meet peak load in California, the Mid-Atlantic, and New York; helped respond to other system emergencies, including addressing sudden changes in generation output in Texas; and participated in capacity markets in the PJM Interconnection and ISO-New England.

## Regulatory Barriers

States and the federal government have also acted to remove regulatory barriers limiting customer participation in demand response, peak reduction, and critical period pricing programs.  Ten states have adopted policies that decouple changes in utility revenue with changes in sales volume.  The National Association of Regulatory Utility Commissioners and FERC established two collaborative efforts to address issues crucial to the effective implementation of demand response and the related topic of smart grids.  There is growing attention to demand response measurement and verification, with many entities such as the FERC, RTOs and ISOs, the North American Energy Standards Board, state electric regulatory commissions, and several regional research entities all examining how to develop measurement and verification protocols or standards that accurately measure load reductions.

However, many obstacles remain.  One such barrier is the limited number of retail customers on time-based rates.  Another is restrictions on customer access to meter data, making information retrieval for customers and their independent aggregators of retail customers time consuming and expensive.  Timely access to customer meter data allows aggregators to assess the demand reductions achieved by their customers.  There is also an increased need to accurately measure load reductions so as to ensure confidence in the ability of demand response providers to actually provide demand response service when needed.  Another barrier is the scale of financial investment required to deploy enabling technologies during an economic downturn.  Finally, the availability of only a limited variety of demand response programs that accommodate the operating needs of potential demand response providers may also be a barrier.  Government and industry have begun programs to address most of these barriers, but significant work remains to be done.

## Recommendations

Staff recommends that the Commission continue to make demand response a priority. Specific recommendations include: (1) continue current coordination with NARUC on finding demand response solutions, with a focus on aligning retail demand response programs and time-based rates with wholesale market designs; (2) continue exploring how to remove barriers to the comparable treatment of demand response resources in wholesale markets; (3) coordinate the Commission's National Assessment of Demand Response and National Action Plan for Demand Response efforts required by Congress in the Energy Independence and Security Act of 2007 with the ongoing annual demand response reporting required by the Energy Policy Act of 2005 to ensure effective use of Commission resources; (4) support the efforts of organizations such as NERC, NAESB, and EIA to develop practical means to measure, verify, forecast, and track demand response; and (5) explore possible linkages among demand response, energy efficiency, and smart grid programs. As required by law, in 2009 the Commission's National Assessment of Demand Response will contain additional recommendations for achieving the nation's demand response potential.

**Attachment 4**

**Draft Dated December 19, 2008**

North American Energy Standards Board (NAESB)

2008 WEQ Annual Plan Item 5(a) Recommendation:
Proposed Business Practices for a Framework for Measurement and Verification of Wholesale Electric Market Demand Response

# Comments of the Electricity Consumers Resource Council (ELCON)

Dated January 12, 2009

The Electricity Consumers Resource Council (ELCON) appreciates the opportunity to respond to the December 4, 2008 Request for Formal Comments on the WEQ Annual Plan Item 5(a) Recommendation.

ELCON is the national association representing large industrial consumers of electricity. ELCON member companies produce a wide range of products from virtually every segment of the manufacturing community. ELCON members operate hundreds of major facilities and are consumers of electricity in the footprints of all ISOs and RTOs in North America that are potentially affected by the recommended business practice standards.

Most ELCON members are "Demand Response Providers" as defined in the Recommendation. They have had years, if not decades, of experience operating under interruptible tariffs and contracts. They have also been participants in the demand response and emergency load curtailment programs of FERC-approved ISOs and RTOs, and ERCOT. Through their membership in ELCON they have followed the progress of the DSM-EE effort by NAESB.

## Comments

ELCON submitted comments to NAESB in response to the October 6, 2008 WEQ informal request on proposed measurement and verification business practice standards for Wholesale Electric Market Demand Response Programs. In those comments we indicated our strong support for NAESB's efforts that produced the draft recommendation. We said it was an important milestone for the industry and applauded NAESB for its leadership role on this important issue.

We also indicated that we reviewed many of the provisions of the proposed standards in the context of how they might be used as barriers to participation even though we did not—at the time—believe that that was the intent of the authors. In the past, the stakeholder process at some ISOs or RTOs has not been a favorably environment for promoting the efficient use of Demand Resources. The generally hostile response from the working group during the December 2 meeting to some of our comments and concerns (as well as to the constructive comments submitted by other parties) forces us to reconsider the motives of the working group and merits of the Recommendations. We are greatly disappointed that simple requests to clarify language that ELCON and the working group would seem to be in mutually agreement were rejected.

Without more forthright consideration of changes to the Recommendation that would produce meaningful standards for promoting the cost-effective use of demand response, <u>ELCON urges the WEQ to reject the Recommendation</u>.

ELCON offers that following comments on the Recommendation.

1. <u>Measurement and Verification</u> - We continue to believe that it is a misnomer and misleading to define these business practices solely in the context of "measurement and verification" (M&V). The proposal does not standardize many M&V functions, but rather, provides a standardized template (or taxonomy) for designing Demand Response programs and offerings in the wholesale electric markets, and provide preliminary capabilities for supporting the measurement and verification of the Demand Resource. There are aspects of measurement and verification that are not covered under this draft recommendation that the industry may seek to address in future standards. Our concern is that approval of the Recommendation in its current form will preclude or relay opportunities in the future to standardize M&V protocols on a more comprehensive basis. We acknowledge (and supported) the amendment during the December 2 meeting to add the word "framework" to the title. But this does not change the fact that the first two items in the "Introduction" are "1. Measurement and Verification Standards" and "2. Applicability of Measurement and Verification Standards." The continued emphasis on M&V misrepresents the actual substance of the Recommendation.

2. <u>Normal Operations/Recovery Period</u> – The standard should not require a return to "normal operations" (implying a return to a higher or the <u>ex ante</u> level of load) unless the Demand Response Provider has been contracted to do so. The Demand Response Provider should be allowed the discretion to remain at the lower Load level after the Demand Response Event. Any other such requirement should be treated as a separate Event. We appreciate the attempt to address this concern by modifying the definition of "Demand Response Event" but we do not

believe the fix actually solves the problem. The applicable definitions should be clarified as follows:

> **Normal Operations** – The time following Release/Recall at which a System Operator may allow a Demand Resource to cease any obligation regarding its Load consumption, and to be available again for Deployment. ("Definition of Terms")
>
> **Recovery Period** – The time between Release/Recall and Normal Operations, representing the window under which Demand Resources may return to their normal or other load level. ("Definition of Terms")
>
> **Release/Recall** – The System Operator shall specify the time at which Demand Resources shall cease any obligation regarding its Load consumption. ("Business Practice Requirements" except for Regulation Products (015-1.12))

3. Demand Resource Availability Measurement – The current provision on Demand Resource Availability Measurement in the Business Practice Requirements is too open ended. We recommend:

> **Demand Resource Availability Measurement** – The System Operator shall specify any reasonable requirements for measuring the capability of a Demand Resource to meet its obligation that do not burden the Demand Resource with unnecessary or unduly costly requirements. ("Business Practice Requirements" – Capacity Products (015-1.4) and Reserve Products (015-1.8))

4. Aggregation – The proposal for Aggregation under the four service types may be subject to abuse or discriminatory treatment of Aggregators. The System Operator should not be in the position to decide who can or cannot aggregate loads. The System Operator should be required to accept resources from Aggregators that are already pre-qualified under applicable state or federal regulations, and the terms and conditions of each ISO or RTO's tariffs. We suggest a new provision:

> **Aggregation** – The System Operator shall treat Aggregated Demand Response on a comparable basis with other Demand Response. ("Business Practice Requirements")

5. Telemetry – There are an abundance of definitions and references to telemetry in the draft recommendation. We recognize that there is a need for telemetry adequate to ensure predictable system operations and reliable confirmation of

instructions by the Demand Resource in providing services. Our problem is with the broad scope of provisions such as "Telemetry Requirements" and "Other Telemetry Measurements" in which there are no implied or explicit limits on what the System Operator may require. We suggest that any requirements (initial or additional) be commensurate with achieving compliance at least-cost to the Demand Response Provider. We do not agree with the working group that our concern is "inconsistent with intent and scope of these proposed standards." To the contrary, any provision that is so open-ended is itself inconsistent with the intent of standards marking.

6. <u>System Operator Discretion to Dispatch Demand Resource for Reasons Other Than for What was Intended</u> – A general concern of Demand Response Providers is committing to provide a specific Demand Response service, and then when the Event actually occurs, the Demand Resource is dispatched as another service. While we understand and appreciate a System Operator's need for flexibility, there is a more compelling need for transparency. We also do not want Demand Response Providers to be put in situations in which they are routinely providing uncompensated services. The working group's responseWe request that the working group address this concern. Also related to this concern is the need for reasonable limits on Events that are triggered as "Call Options." Here the fear is that the System Operator may be overly cautious and tend to over use a Demand Resource. The proposed standards tend to emphasize only the obligations of Demand Resources and not so much (if at all) the complementary obligations of the System Operators. We want to encourage the formation of professional, business-like partnerships, and avoid adversarial relationships.

* * * * * *

Submitted by:

John P. Hughes
Vice President – Technical Affairs
Electricity Consumers Resource Council (ELCON)
1333 H Street, NW
West Tower, Suite 800
Washington DC 20005
Voice: 202.682.1390
Email: jhughes@elcon.org

# Attachment 5

Excerpts on "Energy Efficiency Resources" from the December 12, 2008 PJM Section 205 Filing Amending PJM's OATT and the Reliability Assurance Agreement, FERC Docket No. ER09-412-000

## III. ENERGY EFFICIENCY

### A. Background

The Commission has recognized the importance of energy efficiency in organized wholesale markets[62] and has specifically encouraged a role for energy efficiency investments in RPM. In its orders approving the 2006 RPM Settlement, the Commission observed that while "RPM promotes energy efficiency in broad terms,"[63] RPM did not "treat investment in energy efficiency as a type of capacity resource eligible to participate in the capacity market."[64] The Commission therefore urged that, "to the extent possible, energy efficiency solutions should be able to compete on an equal footing with demand response, generation, and transmission solutions."[65] To that end, the Commission ordered that PJM establish additional processes in its region to pursue and support demand response and incorporate energy efficiency applications in RPM.[66]

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62 Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 125 FERC ¶ 61,071, at P 276 (2008).

63 PJM Interconnection, L.L.C., 119 FERC ¶ 61,318, P 201 (2007) ("June 25 Order) (citation omitted).

64 June 25 Order at P 202.

65 Id.

66 June 25 Order at P 204 (citing PJM Interconnection, L.L.C., 117 FERC ¶ 61,331, at P 32 (2006) ("December 22 Order")).

In the September 19 Order, the Commission again stated that "PJM should develop and implement provisions to enable energy efficiency resources to participate in the RPM auctions."[67] Noting that the RPM Settlement "committed the settling parties to establish an additional process for incorporating energy efficiency applications in RPM," the Commission stated that it expects PJM "will complete this process by December 2008."[68]

Currently, RPM permits participation by demand resources ("DR") that are dispatchable by PJM.[69] However, the reliability value of non-dispatchable resources such as energy efficiency ("EE") initiatives is recognized within RPM only after the impact of EE programs is reflected in the historic load data.[70] RPM's base residual auction is conducted three years before the Delivery Year, but it relies on forecasts based on peak loads from the summer before the auction, i.e., four years before the Delivery Year. As a result, there is a "gap" between when the EE resource is online, but not recognized in the load forecast used in the RPM auctions, and when the EE resource is recognized in the load forecast.

In response to the Commission's orders, PJM and its stakeholders embarked on an extensive process to develop a method to include EE Resources in RPM. PJM's Demand Response Steering Committee ("DRSC") has discussed this issue repeatedly since early

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67 September 19 Order at P 46.

68 Id.

69 Brattle Report at 115 – 117.

70 Id.

2007, and the Markets and Reliability Committee has considered this issue as well. Although the stakeholders have not achieved a consensus on a specific proposal, all the principle alternatives considered would allow EE Resources to participate in the RPM auction.[71]

Accordingly, to move this process forward and ensure that EE Resources can participate in the May 2009 auction, PJM is revising its tariff to enable EE Resources to participate directly in the RPM auctions.

### B. Detailed Description of Tariff Revisions to Incorporate Energy Efficiency in RPM.

The enclosed tariff revisions incorporate EE Resources into the RPM auctions by providing a mechanism to fill the "gap" between the time the EE Resource comes online, and the time its contribution to reducing loads is recognized in the load forecast used for the RPM auctions. For the most part, the changes to incorporate energy efficiency in RPM appear in a new section M to Schedule 6 of the RAA, which otherwise sets forth the criteria, procedures, and standards for demand resources to participate in RPM.[72] Notably, new section M expressly provides that EE Resources are permitted to offer into the RPM auctions starting with the May 2009 Base Residual Auction that will secure

[71] As discussed below, the DRSC considered alternative proposals developed by PJM, Con Edison Energy ("ConEd") and Synapse Energy Economics, Inc. ("Synapse"). The major difference between the proposals concerns how many Delivery Years an EE resource would be allowed to participate in the RPM auctions.

[72] RAA Schedule 6 is repeated in PJM Tariff, Attachment DD-1. Accordingly, all changes to Schedule 6 described below are also being made to Attachment DD-1.

capacity commitments for 2012/2013.[73] As the Brattle Report observed, allowing EE resources to offer into the RPM auctions can reduce both the need to procure other resources and the auction clearing price.[74]

New section M[75] defines an EE Resource as:

> a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods as described herein) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch or operator intervention.

In order to participate, the Capacity Market Seller must first submit a Notice of Intent to offer Planned EE Resource ("Notice") and a Measurement & Verification Plan ("M & V Plan") no later than 30 days prior to the RPM Auction.[76] This Notice must include all project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, the proposed Nominated Energy Efficiency Value and any other relevant data.[77] The M&V Plan must describe the methods and procedures for

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73 See RAA, Schedule 6, Section M.2.

74 Brattle Report at 116.

75 RAA, Schedule 6, section M.1.

76 Id., section M.2.

77 Id.

determining the amount of load reduction and confirming that such reduction is achieved.[78] After review of the Notice and M&V Plan, PJM will determine the Nominated Energy Efficiency Value that may be offered in the RPM Auction.[79]

Any Capacity Market Seller offering an EE Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff, which are the same as those pertaining to planned demand resources.[80]

An EE Resource is permitted to be offered as a Capacity Resource in the Base Residual or Incremental Auctions for four (4) consecutive Delivery Years.[81] As discussed above, this ensures that a party contemplating an energy efficiency investment realizes the benefit of the investment's reduction in the PJM region's capacity needs before that reduction can be reflected in the load forecast used for RPM's forward auctions. After that reduction is reflected in the load forecast, the customer's load obligation, and capacity requirements, are reduced even without the changes proposed in this docket.

For any EE Resource that clears in the auction, the Capacity Market Seller must submit, no later than 30 days prior to each auction in which the resource will be offered, supplemental project status information. In addition, the Capacity Market Seller of any

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78 PJM intends to detail additional standards and procedures for M & V Plans in its manuals.

79 Id.

80 Id., section M.3.

81 Id., section M.4.

EE resource must submit, no later than the start of a Delivery Year, an updated project status and detailed M&V data.[82] The final capacity value of the EE Resource during the Delivery Year shall be as determined by PJM based on the submitted M & V data.

If the Capacity Market Seller submits updated M&V data each year, and clears in the RPM auction each year, it will be paid based on 100% of the capacity value (as determined by PJM) multiplied by the RPM Resource Clearing Price each year.[83] If the Capacity Market Seller submits M&V data only for the first year, it still may collect RPM auction revenues for up to three more Delivery Years, but the revenues it can receive will decrease, recognizing the uncertainty in the continuing benefit provided by the project absent such verification data. Specifically, an EE Resource that does not submit updated M&V data for the subsequent years will be paid based on 75% of the capacity value for the second year, 50% for the third year and 25% for the fourth year).[84]

The Suppliers Group alternative, discussed below, would deny an EE Resource any RPM revenue for subsequent Delivery Years if it does not provide M&V data for those years. This is overly punitive. In effect, this assumes that the project is providing zero benefit in subsequent years. But that is an unreasonable assumption, particularly for a project that satisfied objective measurement and verification criteria in the first year it is in place. Since zero megawatts seems unlikely to be an accurate characterization of the project's efficiency benefits in the second through fourth years, the only reason to impose

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82 Id., section M.6.

83 Id.

84 Id.

such a requirement would be to incent the sponsor to provide M&V data in the subsequent years. But that incentive could be achieved with something well short of a total forfeiture of revenues for all subsequent years. PJM's proposed declining scale should be sufficient to provide any needed incentive, while also bearing a closer relation to the project's likely actual benefit in subsequent years.

Finally, in order to verify the M&V data submitted by the Capacity Market Seller, PJM is authorized to conduct an audit of any EE Resource in the PJM Region.[85]

### C. Other Alternatives Considered by the PJM Stakeholders

While alternative proposals by ConEd and Synapse were considered by the DRSC, PJM's proposal strikes the best balance and is just and reasonable.

Synapse's proposal permits the EE Resource to participate in the RPM auctions and receive capacity payments for the "measure life" of the EE Resource, even if that exceeds four years.[86] However, as explained above, by the fourth Delivery Year the measure is in place, PJM's load forecast will fully incorporate the measure's capacity reduction benefits. Continuing to make a capacity payment to the project sponsor under those circumstances would represent a double-payment for the measure's benefits: once in the form of a foregone capacity payment by the sponsor, and then again in the form of an affirmative payment to the sponsor. This double counting would also have an adverse

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85 Id., section M.7.

86 Synapse's proposal, as presented to the DRSC on October 10, 2008, is posted to PJM's website at: http://www.pjm.com/committees/drsc/downloads/20081010-item-01c-synapse-summary.pdf. Their proposal also has been incorporated into the PJM Load Group comprehensive proposal considered by the MC and MRC.

impact on reliability because the installed reserves provided by energy efficiency would be counted as a resource in the RPM auction and again as a load forecast reduction. This would create the potential for a shortfall in procurement of installed reserves, which would violate reliability criteria.

ConEd's proposal, by contrast, permits an EE Resource to participate as a capacity resource for only one year or, alternatively, for up to four years, but only if the affected customers' peak load contributions are added back in the second through fourth years.[87] The latter alternative has been adopted by the Supplier Group in the comprehensive proposal they presented to the MC and MRC.[88] In support of its approach, ConEd argues that, although the efficiency measure is not reflected in the regional peak load forecast until the fourth year, the customers benefiting from the efficiency measure receive a reduced allocation of capacity obligations and costs, because the efficiency measure is reflected in the second year for obligation allocation purposes. A customer's peak load contribution determines its allocation of capacity obligations, argues ConEd, and that peak load contribution adjusts every year based on the customer's share of peak load in the prior summer. ConEd therefore would, in practice, award an efficiency project revenues if it cleared the auction for years two through four, but then

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[87] ConEd's proposed alternative, as presented to the DRSC on October 10, 2008, is posted on the PJM website at: http://www.pjm.com/committees/drsc/downloads/20081010-item-01b-con-ed-energy-efficiency.pdf.

[88] See "Supplier Compromise Proposal," page 2, item 3(b), posted at: http://www.pjm.com/committees/mrc/downloads/20081119-item-06c-supplier-compromise-proposal.pdf.

negate most or all of these revenues by charging the affected customers for the amount by which the efficiency measure reduced their peak-load contributions.

ConEd's approach does not meet the challenge the Commission laid before PJM and its stakeholders: find a way for energy efficiency resources to participate meaningfully in the RPM auctions, similar to any other resource. In practice ConEd would limit energy efficiency measures to only one year of capacity revenue in PJM, thus offering little incentive to energy efficiency innovators. Moreover, the equity/allocation concerns that motivate ConEd's proposal could as well be addressed by state regulators responsible for apportioning costs among customers served by an electric distribution company.

## IV. INCREMENTAL AUCTION DESIGN AND TREATMENT OF SHORT-TERM RESOURCES.

### A. Elimination of ILR in 2012.

Under the current RPM rules, Interruptible Load for Reliability ("ILR") providers have little incentive to offer into an RPM auction as a Demand Resource rather than wait to certify as ILR just a few months before the Delivery Year. For a resource located in an unconstrained portion of the region, the credit paid to certified ILR is the same as the auction clearing price paid to resources that commit in the BRA.

Indeed, the current rules incent ILR to hold back from the auction. Fundamentally, the current rules allow a resource to receive the benefits of clearing the auction without competing to participate in the auction. Even a price-taking offer provides competitive benefits by displacing higher-cost resources. But ILR need not compete on price, and need not even face the prospect of incrementally reducing the