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ELECTRICITY LAW DEVELOPMENTS – April 3, 2007

Prepared for ELCON

This report summarizes recent developments in FERC proceedings in which ELCON has been active and other matters of interest to industrial consumers. Inside this issue:

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New developments since the March 2007 issue of Electricity Law Developments are **in bold**.

I. FERC PROCEEDINGS

A. FERC issues Final Rule on Mandatory Reliability Standards for the Bulk Power System, Docket No. RM06-16

On March 15, 2007, FERC approved 83 of the 107 reliability standards proposed by NERC. 118 FERC ¶ 61,218. Six of the eight proposed regional differences and the “Glossary of Terms” submitted by NERC were also approved. FERC noted, however, that many of the reliability standards need significant improvement and directed the ERO to develop modifications to 58 of the 83 approved standards. Among improvements to be made are issues raised in the recommendations of the U.S. –Canada report on the August 2003 Northeast blackout. The remaining 24 standards will not be approved until further information is provided.

FERC stated that by approving proposed reliability standards that meet the statutory test while acting to strengthen them assures that the mandatory reliability standards will be in place as soon as possible, then improved over time. The workplan developed by NERC will help identify which standards need strengthening more urgently.

With respect to applicability, the final rule makes two changes from what had been proposed rule in the October 19, 2006 NOPR (117 FERC ¶61,084). First, as ELCON had suggested in its comments submitted on January 3, 2007, the Commission adopted the definition of “bulk electric system” proposed by the ERO, but recognized that the statutory definition of “bulk power system” is more expansive. FERC intends to revisit this in future proceedings. Second, with respect to applicability of the standards to small entities, the Commission accepted the proposal to rely on the compliance registry. Under this approach, only registered entities would be considered “users, owners, or operators” of the bulk

power system subject to enforcement of mandatory reliability standards. This is intended to clarify the universe of entities subject to enforceable reliability standards, assure due process, and provide notice. It will also have the practical effect of exempting many small entities. There are provisions however, to register a previously exempted entity if it is later determined that it should be subject to the reliability standards.

FERC denied the request made by some commentors for a trial period. The standards are mandatory and immediately enforceable. However, recognizing that the primary burden of enforcing the standards will fall on the regional entities, with limited enforcement resources, the final rule directs the ERO and future Regional Entities initially to direct their resources on the most serious violations. They are also directed to exercise enforcement discretion with regard to all applicable users, owners and operators of the bulk power system and not just those new to the reliability scheme. According to FERC, this approach will ensure that compliance monitoring and enforcement processes work as intended and will allow all entities adequate time to implement the new processes.

A list of the specific standards approved, with details of the requirements of each standard, is available on the FERC website at

<http://www.ferc.gov/industries/electric/indus-act/reliability/standards.asp>

In a separate action, described in more detail below, FERC proposed to eliminate the exemption from the reliability standards for QFs of 20 megawatts generating capacity or more, noting that “from a reliability perspective, there does not appear to be a meaningful distinction between QF and non-QF generators that would warrant exemption.”

B. FERC proposes Application of New Mandatory Reliability Standards to all QFs in excess of 20 MW (Docket No. RM07-11)

On March 15, 2007, FERC proposed to eliminate the exemption from the reliability standards for QFs of 20 megawatts generating capacity or more. (“Applicability of Federal Power Act Section 215 to Qualifying Small Power and Cogeneration Facilities,” 118 FERC ¶ 61,220). The NOPR clarifies that PURPA qualifying facilities (QFs), including cogenerators, with nameplate rating of 20 MVA for a single unit or 75 MVA for multiple units at a single bus (“large QFs”), are subject to NERC reliability standards. In effect, FERC is proposing to close a loop hole that might suggest that ALL QFs are exempt from any bulk-electric system reliability obligations. The “loophole” was brought to FERC’s attention in connection with the reliability NOPR when the certain QF groups had asked for QFs to be exempt from FPA Section 215, which grants FERC jurisdiction over “all users, owners, and operators of the bulk-power system” for “purposes of approving reliability standards. . . and enforcing compliance with [section 215]”, and further provides that “[a]ll users, owners and operators of the bulk-power system shall comply with reliability standards that take effect under this section.”

The NOPR appears to preserve the discretion NERC and the regional councils may exercise to exempt large QFs that they may deem not material to reliability. So far, NERC and the regions have given large QFs light-handed treatment and relatively few have been proposed for the NERC Compliance Registry. FERC’s NOPR states that there are 745 large QFs (23% of all QFs in the U.S.) that might be so impacted.

ELCON plans to submit comments indicating that it does not oppose the registration of those QFs whose operations, in the judgment of the North American Electric Reliability Council (“NERC”), do in fact affect bulk power reliability. However, FERC

should not override the judgment of the NERC registration process and force the registration of all QFs above 20 MW regardless whether or not the QF's operations have an effect on reliability. Not only is such a result unneeded to serve the reliability enhancing objections of section 215, but forcing all large QFs into the registration mold needless impairs the viability of QFs without serving a reliability objective. FERC should not micromanage the registration criteria that NERC proposes to apply, but allow the process to unfold and focus on those QFs whose operations affect bulk power supply. This approach serves dual objectives of assuring that those facilities that should be registered are registered and reflecting an awareness of the unique operating characteristics of QFs which are not just like all other generators.

Comments are due April 17, 2007.

**C. Conferences on Competition in Wholesale Power Markets
FERC Docket No. AD07-7**

On February 27, 2007, FERC held the first in a planned series of public conferences to evaluate the state of competition in wholesale power markets. The conferences are designed to explore a range of issues, including federal-state cooperation, the need for new infrastructure, demand response and renewable energy, the availability of long-term contracts and market design issues affecting wholesale markets. The Commission hopes to address the challenges faced by all wholesale markets, including organized markets and bilateral contract markets.

Panelists had differing views on the state on the success of wholesale power markets. ELCON participated in the first panel during the conference and challenged participants to answer the question whether there is any evidence that the power markets today are competitive. After roughly a decade of experience with restructuring, ELCON argued,

there are clear indications that the FERC-approved ISO and RTO markets are too costly, not truly competitive, and fail to deliver net consumer benefits. Restructuring has replaced the old state regulatory regime that had at least some end-user focus and rates based on average costs with a costly ISO/RTO federal regulatory regime that has no end-user focus and rates based on the highest accepted bid.

Several panelists, including Paul Joskow of MIT and Exelon CEO John Rowe, remarked that the cause in the rise in wholesale prices over the past several years is due not to a flaw in the structure of the markets but instead is the result of sharp increases in the prices of natural gas and oil.

Linda Stuntz, former Deputy Energy Secretary, suggested that FERC examine the bidding mechanism utilized by the organized power markets. Most use single-price auctions where the highest accepted bid sets the market clearing price for all accepted bids, which means that generators fueled by natural gas are setting the clearing price.

ELCON recalled that under regulation, the cost increase of one fuel source did not necessarily impact 100% of a utility's generation fleet. Compare this to today, ELCON noted, where everyone is paid the highest price to clear the market, which translates to 100% of a utility's price reflecting the cost of gas because gas is frequently on the margin.

Rowe of Exelon disagreed and commented that the single-price auction attracts "the investment and innovation needed to ensure our future energy security and address global climate change, without burdening consumers with the cost of someone else's plans."

Joskow echoed Rowe's remark, stating "That's how you pay for the capital costs of new capital-intensive technologies, including wind, which has zero fuel costs." Former FERC Commissioners Bill Massey and Elizabeth Moler were also skeptical about the benefit of

changing the bid mechanism because, as Massey stated, there is a “bidding discipline that is built into the single-clearing price” that is not found in other models, such as an as-bid market.

Both Moller and Massey acknowledged that there are still improvements to be made to the markets, including promotion of demand-side resources and elimination of discriminatory transmission policies.

Harvard economist Bill Hogan urged the Commission to focus on a few specific “persistent” but “fixable” problems with existing markets, including scarcity pricing and demand response. “Without improvements in a few elements of market design, ranging from short-term scarcity pricing to long-term transmission rights, the pressure will continue to build for the regulator to step up and make long-term commitments.

On March 12, 2007, ELCON filed supplemental comments offering several suggestions to FERC as it goes forward:

- The Day Two construct is not working for the benefit of end-use consumers as required by the Federal Power Act. LMP is not robust enough to compensate for inadequate infrastructure and should never have been implemented without additional transmission and the elimination of major load pockets. LMP will not work unless enough infrastructure is in place to sufficiently mitigate the consequences of joint generation-transmission ownership of incumbent utility holding companies. Price signals are clearly not stimulating, and are probably discouraging, new infrastructure investment. Federal and state regulators do not share the same vision for the industry, which accounts for lack of demand response, and disagree about how resource adequacy should be determined
- FERC should initiate an inquiry into whether today’s RTO platform, with LMP, can be made a viable market model. ELCON questions whether the necessary preconditions are achievable and capable of delivering net benefits to end-use consumers?
- Simple technical fixes or additional regulatory intervention will not correct the inherent problems. FERC must be ready to substantially change the basic underlying structure and implement tariffs that provide consumers just and reasonable rates. Additional patches will not fix the problems.

- **If conditions necessary to implement LMP cannot be achieved, the policy debate must shift to what form of regulation is appropriate for jurisdictional utilities: state, federal or a combination of the two.**

ELCON identified some particular areas are in need of the Commissions attention:

Demand response: For all the studies that have been done on demand response in recent years, little in the way of implementation of demand response markets (as opposed to programs) has occurred. Price-responsive load must have access to the price-setting mechanisms of the short-term energy and ancillary services markets without restrictions that would create a bias for the bids of generators. Even minimal participation during high-priced hours can substantially reduce LMPs during those hours and reduce the cost of hedging products going forward.

Centralized capacity constructs fail to attract investment: Investment in generation has all but ceased in the organized markets, and transmission investment is not far behind. The Day Two markets are not real markets – they are regulation without a rate base. Efforts to remedy the problem with artificial centralized capacity constructs are clear indications of market failures. Perhaps worse, these constructs are not trusted by either generator owners or Wall Street.

Lack of forward markets: The absence of a robust forward market prevents the financing of new generation with long-term bilateral contracts. Incumbent generators have no economic incentive to increase generating capacity because it would reduce the prices they would otherwise receive for their strategically located units. Consumers needing to hedge risk are left with the choice of the unbundled spot price (the highest bid clearing the market) or a contract based on estimates of these same spot price bundled with a hefty risk premium.

RMR units are able to extract rents and hold the market hostage. Rather than facilitating ease of entry and exit, the FERC-approved organized markets are distorted. Generators in organized markets are increasingly offered the higher of market or cost to stay in business because such units are typically needed for reliability-must run purposes and there is a lack of new market entrants that would otherwise compete with the RMR units.

Nodal pricing: The nodal pricing model component of FERC's standard market design is not sufficiently robust to compensate for inadequate transmission infrastructure. This fact is demonstrated by growing congestion, and therefore, growing congestion-generated revenues for generators.

Inadequate transmission infrastructure: Inadequate transmission infrastructure stifles liquidity at congested nodes, which tends to exacerbate and preserve local market power (and preserve an under built infrastructure), and increase the potential frequency and severity of scarcity pricing.

The Energy Producers and users Coalition and Cogeneration Association of California filed comments similar to comments ELCON has filed elsewhere. Among the concerns they identify in the western markets are the “absence of a vibrant and accessible market for QFs.” Transmission constraints and difficulties in siting and constructing new transmission facilities render QFs a captive resource of the interconnected IOUs. They also insist that the mere existence of bilateral contracts in a market does not reflect meaningful access to that market and cite several specific examples of discrimination in bilateral contracts in the California markets.

NRECA expressed concern that the promise of lower cost in the long term has not been realized and may not be achieved going forward due to institutional and infrastructural barriers. They identify three “fundamental impediments” to achieving generation competition that will benefit consumers: a lack of sufficient transmission to allow buyers to meet sellers and to overcome market power of incumbents; an excessive focus on short term issues; and a “continuing and even growing lack of confidence in the markets themselves, particularly from those who are being ‘served’ by those markets.” They also list a “steadily shrinking long-term bilateral market” and the lack of long-term transmission service at reasonably predictable costs to facilitate longer-term power purchase agreements and permit generation financing and construction as “disappointments”. As for successes, NRECA remarks that “the lights have stayed on despite significant changes in industry structure.”

PJMICC, together with other industrial customer groups, highlighted comments on design flaws in the organized markets filed in other proceedings and urged FERC take action in light of those comments as a way of beginning to correct shortfalls in the wholesale power markets. Focusing on RTOs, they suggest that in a real competitive market, power prices would not be dictated by RTOs or regulators; suppliers would seek out customers and offer long-term bilateral contracts and invest in innovation; barriers to entry and exit would be minimal; and elasticity of demand would not be an ever-present challenge.

Not surprisingly, the grid operators had a different reaction to the conference. PJM criticized ELCON’s remarks, characterizing them as “broad conclusory statements concerning a lack of progress made in organized competitive markets.” Generators are not

receiving excessive energy revenues in PJM's single-clearing price market, PJM insists, and the presence of organized markets does not inhibit the ability of LSEs to enter into long-term bilateral contracts. PJM also took issue with the notion that it does not promote adequate demand response, pointing to its integration of demand response into its RPM program and into the ancillary services market.

MISO asserted that the RTOs and ISOs are well-positioned to "guide wholesale markets to a more competitive state through independence and transparency and by providing consumers and policy makers with alternatives in these wholesale markets" through services provided in their tariffs. Among the challenges facing wholesale competition are attracting new investment, sending accurate price signals, long-term contract availability, transmission congestion, and development and incorporation of more efficient energy resources (demand response and renewables).

The NYISO commented that it has had a number of significant successes and some unexpected difficulties, but that on the whole, the successes substantially outweigh the disappointments.

The final panel of the day focused somewhat more narrowly on successes and failures in regions that rely on wholesale bilateral markets.

EPSA stated that wholesale competition is lacking in bilateral markets and in some regions, particularly the Southeast, there are no bilateral markets to speak of. It believes that Order 890 has the potential to improve transmission access but needs to be aggressively implemented. Primary challenges facing the system, in EPSA's view, are the need for competitive procurement and the risks faced by consumers of rate based investments.

EPSA believes that the need for new generation in bilateral markets is imperative and that competitive procurement is the key to controlling generation costs and risks in the current environment. Arguments against competitive procurement are addressed and negated. EPSA concludes that the failure to address the identified challenges will result in an extremely costly system for decades to come.¹

APPA filed comments indicating the belief that bilateral markets are working relatively well in achieving key consumer-interest goals, including provision of power at reasonable prices, reliability and facilitation of new investment. However, there is room for improvement in two areas: regional planning and coordination and pervasive transmission discrimination in certain markets. They recommend strong enforcement of Order 890 and joint ownership of generation and transmission to ameliorate this problem. APPA also expressed concern about adverse impacts on bilateral markets caused by RTO-run Day Two markets. They cite as an example that generation owners faced with the opportunity to earn high margins in RTO spot markets have little incentive to enter into long-term contracts in adjacent bilateral markets that do not produce similar returns.

D. TDUs and IOUs seek Rehearing on OATT Modifications in Order 890 Docket Nos. RM05-25 and RM05-17

On February 16, 2007, FERC issued Order 890 reforming its open-access transmission tariff with the goal of reducing or eliminating undue preference in transmission service. Not surprisingly, numerous groups have requested rehearing.

EEI submitted a lengthy list of requested technical clarifications and comments. First on the agenda was the requirement that transmission providers choose one of three

¹ See <http://www.epsa.org/forms/documents/DocumentFormPublic/view?id=7E4900000011>.

NERC-approved methodologies to calculate ATC. In the interest of system reliability, FERC should give NERC “guidance and direction” rather than prescriptive instructions for the development of standards for ATC calculations. EEI also expressed concern with the requirement that stakeholders be given the right to request high priority studies annually to address congestion and/or the integration of new resources or loads. EEI requests that FERC specify that stakeholders as a group (and not stakeholders individually) may request 5-10 studies. To be required to provide more would interfere with the ability to perform studies in response to specific requests for transmission service.

EPSA weighed in urging FERC to clarify that ATC be disclosed in real time, that NERC and NAESB be required to develop standards that force transmission owners to post “essential details” of existing transmission commitments, and that transmission owners post results of system utilization.

APPA and NRECA focused on the lifting of price caps for reassignment of capacity. This, APPA argued, “is a recipe for undue discrimination and unjust and unreasonable transmission rates,” possibly leading to customers being forced to pay high premiums without caps for needed capacity.

The Transmission Access Policy Study Group cited numerous issues, among them numerous concerns with FERC’s treatment of rollover rights and the failure by FERC to impose requirements to mitigate acknowledges discrimination in transmission expansion and to impose a clear requirement on transmission providers to construct planned upgrades on a non-discriminatory basis. Similarly, NRECA also urged FERC to confirm that the obligation to expand is a critical component of the transmission providers obligation to plan for its network. EPSA and a number of coops indicated the desire to

have a role in the regional planning process with “full access to the information and models necessary to participate and provide meaningful input.”

The Steel Manufacturers Association asserted that the Commission’s mechanism for addressing energy imbalances does not remedy the underlying deficiencies of the penalty scheme in the former OATT, and instead creates a strong disincentive to significant levels of demand response “since loads that curtail consumption in response to price signals or calls from the system operators necessarily deviate from the established energy consumption schedules.” They argue that the penalty tiers established in the revised rule are at odds with the intent to promote demand response.

E. FERC holds Technical Conference on Merger Review Standards (Docket No. AD07-2)

On March 8, 2007, FERC held a technical conference to assess the adequacy of its merger analysis standards in light of regulatory changes brought about by EPAct 2005, including repeal of PUHCA 1935 and FERC’s new authority under FPA section 203. In connection with Order 669 (transaction subject to FPA section 203), several commentors had suggested that the Commission revisit its merger review policy, and particularly the 1996 merger policy’s “Appendix A” analysis used to measure horizontal market power. FERC asked panelists to comment on the effectiveness of Appendix A analysis, and whether the Commission should consider use of other tools or factors to evaluate a transaction’s effect on competition, rates and regulation.

Among the invited panelists were individuals with merger review experience at the FTC, the DOJ, the American Antitrust Institute, and the Commission, as well as in private practice.

Mark Frankena, Deputy Director for Antitrust at the FTC, told FERC that although the merger policy statement was supposedly based on the FTC and DOJ merger guidelines, appendix A is “totally inconsistent” with the guidelines and is not reliable. “Appendix A can find problems that don’t exist and miss problems that do exist.” He suggested that FERC’s analysis should include a consideration of factors that constrain prices prior to a merger and how or if they will be constrained after a merger.

University of Houston Law Center professor Darren Bush, formerly a trial attorney at the DOJ, characterized appendix A as “inadequate” because it attempts to use traditional tools to measure concentration in a non-traditional market. He was also critical of FERC’s practice of relying on the applicant’s economic analysis, pointing out that such analysis is biased from the outset.

Diana Moss of the American Antitrust Institute agreed with Bush that FERC should be wary of an applicant-filed analysis of the competitive effects of a potential merger. “Relying on an applicant’s analysis leads to inconsistent assumptions and results.” She also suggested that FERC look at the whole market power picture, including barriers to entry, the potential of a dominant firm to withhold capacity, or the possibility for rivals in an oligopoly setting tacitly to collude on price or quantity.

Former FERC Commissioner Mike Naeve, now practicing with Skadden, Arps, Slate Meagher & Flom, stated that the fact that FERC’s review differed from that of FTC or DOJ was not necessarily negative. Having multiple agencies review a merger adds a

“double level of insurance.” In his view, the Appendix A screening process has been effective to date. If FERC does decide to change its merger analysis, however, he asked that whatever methodology is adopted be transparent so that companies may continue to self-screen potential mergers in advance, as they do now.

At the end of the conference, Chairman Kelliher stated that he had not been persuaded that FERC’s existing merger analysis was in need of major overhaul. However, he agreed that the policy statement might be in need of updating and invited specific proposals on those changes that may be needed.

F. Technical Conference on Demand Response in Wholesale Markets (Docket No. AD07-11)

FERC has announced that a technical conference will be held on Monday, April 23, 2007, at 9:00 am (EST), on integrating demand response in wholesale markets, including items previously set for conference in the Commission’s order in *PJM Interconnection, L.L.C.*, (Order conditionally accepting proposed changes to PJM’s Regional Transmission Expansion Planning Protocol, 117 FERC ¶ 61,218, at P 45 (Nov. 21, 2006)). Among items for discussion at the conference are the feasibility of employing demand response resources as cost-effective alternatives and/or complements to transmission expansions and what mechanisms (*e.g.*, market or regulated) should be considered for compensating demand resources that are found to be feasible alternatives and/or complements. The agenda for this conference is not yet available.

G. PJM annual State of the Market Report

On March 8, 2007, PJM's MMU released its 2006 State of the Market report,² which concludes that all PJM markets were competitive except for the regulation market about which no determination is made.

Contrary to previous years, the PJM regional capacity market is determined to be competitive despite serious concerns about market power, including "high levels of supplier concentration, frequent occurrences of pivotal suppliers, extreme inelasticity of demand and lack of market power mitigation measures." The MMU recommends implementation of rules included in the RPM tariff to stimulate competition, provide incentives for performance, to provide locational price signals, and to provide forward auctions to foster new entry.

The MMU also recommends that PJM evaluate "additional actions to increase demand-side responsiveness to price in both Energy and Capacity Markets and of actions to address institutional issues which may inhibit the evolution of demand-side price response." The MMU also suggests that PJM and the MMU continue to improve demand-side resource rules to ensure that market power is not exercised on the demand side of the market and to reduce barriers to further development of demand response, particularly in the interface between wholesale and retail markets.

Additional recommendations include:

- **Enhancements to PJM's scarcity pricing rules to create stages of scarcity and corresponding stages of locational scarcity pricing in order to ensure competitive prices when scarcity conditions exist in market regions. Particular reference is made to current rules under which a scarcity pricing event sets prices for all generators in the defined area at the same level, equal to the highest accepted offer within a scarcity pricing region. The MMU recommends replacing this price signal with locational signals.**

² available at <http://www.pjm.com/index.jsp>

- **Implementation of targeted, flexible real-time market power mitigation in the Regulation market;**
- **Consistent application of local market power rules to all constraints; and**
- **Consideration by FERC of ending the exemption from offer capping currently applicable to certain units which were constructed in reliance on the later-terminated exemption for units constructed after 1996.³ According to PJM, a small number of exempt units accounted for a disproportionate share of markup in 2006, leading the MMU to suspect the exercise of market power.**

H. ELCON intervenes in support of Gerdau Ameristeel’s protest to PJM’s proposed Load Response Rules (Docket No. ER07-508)

On February 2, 2007, PJM filed proposed revisions to its economic load response rules, explaining that the change was needed “to address the problem of entities engaging in activity using PJM’s demand-response market access which does not provide the demand-response benefits that PJM’s economic load-response program was designed to produce.” The existing rules allow participants in the program to buy and sell in the same day-ahead market upon which the retail LMP rate is indexed, but prohibit such activity in the real-time market. According to PJM, entities with day-ahead LPM-based contracts are able to game the system by submitting demand reduction bids in the day-ahead market when LMP is above \$75/MWh in order to receive the economic-load response incentive irrespective of whether they intend to consume energy for that period.

Gerdau Ameristeel Corporation (“Gerdau”) on February 23 filed a protest, citing, among other concerns, two issues of particular importance to ELCON members: first, PJM’s proposed revisions fail to treat demand response symmetrically with generation; and second, PJM’s assertion that a majority of stakeholders approved the plan does not paint an accurate picture of

³ These units were grandfathered, subject to possible future mitigation if PJM or its market monitor concluded that they were exercising significant market power. 110 FERC ¶61,053 (2005).

stakeholder support. An entire sector of stakeholder representatives – the End Use Customer representatives. ELCON filed comments February 23 in support of Gerdau's protest on these issues.

Asymmetrical Treatment of Resources

PJM's proposal does not treat demand response symmetrically with other resources. A decrease in a MW consumed has the same effect on the system as an increase in MW generated, therefore demand response should be treated symmetrically and priced on the same basis as a generator. Gerdau pointed out that such treatment is not accorded demand response within PJM, citing a mismatch between the value of reductions in energy during an August 2006 heat wave (\$650 million) and the corresponding payments made for demand response (\$5 million).

PJM's argument is that customers that take LMP prices should benefit only from the savings they receive by not buying power (the value of the LMP at the time) and not receive any incentive in addition to those savings. The same logic applied to a generator is that they save money (fuel costs) by not generating and therefore should be very happy if they are not generating. PJM also claims that some industrials might "game" the program by making the offer in the day-ahead market but not following through in the real-time market. PJM is not proposing to ban generators from the day-ahead market because they might game their bids. ELCON argued that this issue ignores the fact that the RTO's Market Monitoring Unit's job is to monitor such behavior regardless of the type of resource doing the bidding.

ELCON commented that asymmetrical treatment of demand-side resources aggravates the problem of limited opportunity for demand resources to participate in the market and noted that both PJM's MMU and FERC Staff have previously recommended steps to *increase* demand-

side participation in the market. For example, in an August 2006 report on demand response, FERC staff stated:

Demand Response deserves serious attention. Staff recommends that the Commission: (1) explore how to better accommodate demand response in wholesale markets; (2) explore how to coordinate with utilities, state commissions, and other interested parties on demand response in wholesale and retail markets; and (3) consider specific proposals for compatible regulatory approaches, including how to eliminate regulatory barriers to improve participation in demand response, peak reduction and critical peak pricing programs.⁴

ELCON pointed to the numerous benefits of demand response. Market participants see lower or at least more stable wholesale and retail prices and can create additional choices in retail markets to manage customer load and costs. Less demand on the system translates to less need to build additional generation or transmission and distribution infrastructure, particularly since demand response resources can be called upon relatively quickly to relieve problems in load pockets. Customers save costs in their energy bills from reduced consumption and at the same time obtain reliability benefits. Demand response can also be a tool for mitigating generation market power in periods of high demand. In order to maximize these recognized benefits to all market participants, resources must be treated on equal footing.

Stakeholder Objections to PJM's Proposal

ELCON joined Gerdau in urging the Commission to act independently of the outcome of the skewed PJM stakeholder process. PJM states that its proposal “was endorsed by a clear majority.” PJM’s February 2, 2007, Filing at p.6. However, what PJM failed to reveal was that ten End Use Customer Sector representatives of the Members Committee had objected to the proposal and had requested that the objection be reflected in the record and minutes of the

⁴ Federal Energy Regulatory Commission Staff Report, “Assessment of Demand Response and Advanced Metering” (“2006 Demand Response Report”), FERC Docket No. AD06-2-000 (August 2006) at xii, available at <http://www.ferc.gov/legal/staff-reports/demand-response.pdf>.

meeting during which the proposal was placed on the consent agenda. PJM never responded to this request. ELCON argued that a stakeholder process that ignores the views of an entire class of stakeholders is neither balanced nor representative. While it is appropriate for FERC to consider the stakeholder process, FERC is not bound by the outcome, particularly where the process is flawed.

Interventions were also filed by the Steel Manufacturers Association and by PJM Industrial Customer Coalition.

On March 12, 2007, PJM filed a response urging FERC to reject the protests and approve its proposal. In general, they argue that PJM's demand side programs:

... are close to the interests of state regulators because they involve end-users, and because the costs of such programs are allocated to the specific end-user's load serving entity ... for the economic payments, and to all LSEs in a zone for incentive payments. Ultimately, such costs potentially flow downstream to other end-use customers of the LSE. Accordingly, to ensure the success and continuing evolution of PJM's demand side programs, the programs must retain their integrity in order to receive the continuing support from all interested parties affected by the programs.

Pertinent to this proceeding, PJM's demand side programs include subsidization and socialization elements that must be effective and free from criticism that such programs amount only to "corporate welfare", or are compromised by ineffective transactions that offer no real demand side benefit to the system. Accordingly, in the view of PJM, and the majority of its stakeholders, it is important to the continued success and integrity of PJM's demand side programs to remedy the loophole addressed by the filing because the sorts of transactions in question are contrary to the intent of the program, and undermine the efficacy thereof.

In response to concerns specifically raised by ELCON, PJM insists that generation and demand resources are in fact treated symmetrically in their proposed rule change, while the present system is problematic in that it contains an asymmetry that gives preference to demand side resources:

What [the protesting] parties ignore, or fail to understand, is both basic and essential to appreciating the reasonableness of the proposed rule – namely, that unlike other resources, notably generators, PJM’s programs to encourage demand side participation contain important subsidy and socialization elements. Except under limited operating scenarios, generators receive LMP for their supply. In contrast, demand side providers under fixed price contracts enjoy the fixed price savings realized and the full LMP incentive payment when LMP is equal to or greater than \$75MWh. By not allowing those end-use customers exposed to LMP through their retail contracts an opportunity to realize this subsidy, PJM is, in fact, treating these resources “symmetrically” with generation.

As for stakeholder support of the proposal, PJM argues that its statement that the proposal “was endorsed by a clear majority” “implies the endorsement was not unanimous.” They say that it is “noteworthy that only 14 out of 30 End-Use Customers voted at the meeting ...[and] out of the 14 present at the meeting, only 10 opposed the proposal. This indicates that the issue may not have been as critical to the End-Use Sector as a whole, but rather only to a small group of similarly situated members in that group with an interest in maintaining their ability to receive an inefficient subsidy at the expense of other loads in the PJM region.”

On March 27, 2007, Gerdau filed a limited response to PJM’s answer. According to Gerdau, PJM had ample opportunity to present the arguments raised in its Answer, as well as affidavits supporting the theoretical underpinnings of the proposed tariff changes, as part of its initial filing. PJM did neither. “Intervening parties should know the totality of a proposal, and the grounds for the filing party’s proposal, as part of the initial filing.”

Gerdau takes particular issue with PJM’s characterization that its proposal is intended to close a “loophole” when the feature it attempts to address in fact has been a component of PJM’s Day-Ahead ELRP for several years, and is part of the FERC-approved ISO-NE and NYISO load response programs. While in theory the goals of the

proposal might have merit, “[t]he end state objective must be just and reasonable prices for customers.” Gerdau argues:

For customers in New Jersey, ... the ‘just and reasonable’ standard has been stretched to the point where prices are barely affordable. By providing demand response credits to DA LMP Customers that participate in the Day-Ahead ELRP comparable to those being provided in other RTOs, PJM’s current approach is helping to meet the end-state objective of just, reasonable, and affordable electricity prices. It does so by providing a mechanism to hedge against price volatility, schedule production in a manner that optimizes the use of manufacturing equipment, and ensure that consumption is not place on the grid when it would otherwise raise energy and operating reserve costs for other customers. If PJM’s current approach is modified as PJM proposes, it will reduce participation in the benefits derived from the Day-Ahead ELRP.

FERC has not yet addressed the protests in this proceeding.

II. STATE PROCEEDINGS

A. California Rulemaking Proceeding on Resource Adequacy Requirements CPUC Docket No. R.05-12-013

In December of 2005, the California Public Utilities Commission (CPUC) instituted a rulemaking proceeding to consider features of a resource adequacy requirements (RAR) program, including capacity markets in California, which had been proposed in an earlier proceeding. The previous proceeding had led to the establishment of the CPUC’s RAR policy:

First, the Commission seeks through RAR to ensure that the infrastructure investment required for reliability actually occurs. Second, the Commission seeks to ensure that the generation capacity made possible through that investment is available to the grid at the times and at the locations it is needed. Third, the Commission intends that capacity must be sufficient for stressed conditions, i.e., sufficient generation should be available under peak demand conditions even when there are unexpected outages. Finally, the Commission noted that the traditional utility role in procurement included the responsibility to provide reliable service at least cost, and that this is one of the “same issues” of traditional

resource procurement that RAR seeks to address. Thus, the concept embodied in the phrase “reliability at any cost” is not a policy option. Ultimately, measures that are proposed to promote greater grid reliability should be evaluated by weighing their expected costs against the value of their expected contribution to reliability.

Order Instituting Rulemaking, December 15, 2005 (R.05-12-013), at 4 (available at www.cpuc.ca.gov).

The CPUC announced that its intention in this rulemaking is to give effect its RAR policy, with the first priority being the development and implementation of a local capacity component. Other matters to be considered in the rulemaking proceeding include whether the RAR program is appropriate for smaller and multi-jurisdictional IOUs and clarification of procurement obligations and consequences for noncompliance. The proceeding was divided into two phases. Phase one, which is now well underway, includes discussion of local RAR issues, tradable capacity product, and penalties for noncompliance. Among the topics for consideration in Phase 2 are multi-year RAR; zonal RAR; and the establishment of appropriate RAR for smaller entities; and (of particular interest to ELCON) discussion of capacity markets, including whether and how to develop a centralized capacity market regime. Phase 2 will include review of the August 25, 2005 CPUC Capacity Markets White Paper in which the CPUC Energy Division weighs some general pros and cons of capacity markets, looks at existing capacity market models and makes a number of recommendations regarding design issues for the California market:

1. Adopt a short-run capacity market approach with a downward sloping capacity-demand curve for CAISO
2. Further investigate alternative availability metrics (e.g. UCAP v. ISO-NE’s proposed metric based on performance during shortage conditions) and ensure development of an availability metric that is applicable to hydro, wind, thermal and other generation technologies, and to appropriate demand response products.
3. Consider subtraction of peak energy rents from the capacity payment.

4. Adopt reasonable locational installed capacity requirements with locally varying demand curves.
5. Consider protecting against capacity exports during time of tight supply through the use of capacity prices that fluctuate seasonally.
6. Investigate the dependability of capacity import contracts during times of high West-wide load.
7. Make the fixed-cost recovery curve explicit.
8. Strive for regulatory credibility.

The Bilateral Trading Group, a coalition of consumer and other groups that oppose adopting a centralized capacity market (CCM) in California and favor a bilateral market, submitted a proposal on March 30, 2007. As an alternative to CCMs, the BTG suggests that an energy-based market with forward contracting would be a superior means of assuring adequate investment in generation, while improving price signals for customers, and reducing the risk of overpayment by these customers. “Proposals for capacity markets are premised on the assumption that generators cannot anticipate being sufficiently compensated in the energy and ancillary services markets, particularly given the existence of energy price caps. Proponents argue that such price caps are politically inevitable and are particularly problematic for peaking capacity, since it often run at most a few hundred hours per year, during which it must recover both its fixed and variable costs.” BTG asserts that an energy-based market, if properly constructed, also can provide sufficient compensation for generators, citing the examples of markets in Texas, the UK, Australia and Alberta. “The reason these markets have worked without such price gouging is because very little energy is sold in the short-term market. ... Trading too much energy

through short-term markets allows suppliers to exercise considerable unilateral market power.”

On March 30, 2007, ELCON filed comments in support of the BTG’s proposal. In particular, ELCON noted the following strengths in the BTG’s filing:

(1) It provides for a decentralized wholesale electricity market that allows consumption and investments decisions to be driven primarily by energy price signals. This creates a market with the look and feel of other commodity markets. Generators will have the opportunity to be fully compensated for their fixed and variable costs from revenues from the sale of energy and ancillary services in the short-term market, the sale of reserves with physical and financial call options, or long-term forward contracts. There would be no need for artificial “capacity charges” to account for “missing money.” This approach minimizes the risk to consumers that they will overpay for generation investments, especially payments intended for new investments that are never actually built.

(2) The commodity price risk is managed and hedged with bilateral contracts based on the counter-parties’ respective risk tolerance. The proposal overcomes the concern regarding “scarcity pricing” by ensuring that any increase in the level of price caps is commensurate with implementation of forward hedging, demand response and market power mitigation. These essential pre-conditions were absent from the market during the 2000-2001 California energy crisis.

(3) The BTG proposal appropriately recognizes the value of price-responsive load as a resource that can minimize the need for new generation at the time of system peaks and to mitigate unilateral market power. Demand response provides a very efficient solution to the relatively low system load factors (approximately 50%) of California utilities. On systems in which generation resources sit idle almost half the time, it does not make economic sense to add additional capacity resources, especially in the form of higher Planning Reserve Margins (PRMs). The BTG proposal increases the focus on flattening loads to get more value out of existing generators. Encouraging new capacity that only further degrades system load factors will act to shut out demand-side resources and increase prices paid by consumers.

(4) The development of a resource adequacy electronic bulletin board (RA EBB) to ensure intermediate-term resource adequacy provides a low-cost and efficient means of enabling the trading of capacity resources until a fully functioning forward market is developed. The RA EBB would be designed with the same functionality of a CCM, except that price formation would occur entirely through voluntary bilateral transactions between buyers and sellers, rather than through centralized administrative mechanisms that poorly mimic the competitive outcomes of a forward market. The RA EBB can provide a continuum of capacity products that should more than adequately address the concerns of LSEs with respect to load migration.

(5) The proposal interfaces with other California energy policies without creating any undue losses in economic efficiency.

ELCON voiced its strong agreement with the BTG that there is no need for a CCM. ELCON pointed to the examples of the eastern and overseas markets and stated that to date there is no evidence that these CCMs provide a funding mechanism superior to long-term contracts for spurring investment in new long-term generation.

III. COURT PROCEEDINGS

A. Supreme Court chides EPA for failure to implement Clean Air Act

On April 2, 2007, the U. S. Supreme Court issued two decisions relating to Administration implementation of the Clean Air Act.

In Massachusetts v. EPA, No. 05-1120, 2007 U.S. LEXIS 3785, the U.S. Supreme Court (divided 5-4) ruled that EPA must justify its decision not to regulate automobile emissions under the Clean Air Act. Noting that EPA has the authority to regulate automobile emissions under the Act, the majority stated: "In short, EPA has offered no reasoned explanation for its refusal to decide whether greenhouse gases cause or contribute to climate change." The Court's opinion does not categorically require regulation.

According to the majority opinion, authored by Justice Stevens: "We hold only that EPA must ground its reasons for action or inaction in the statute." EPA clearly has the authority to regulate emissions: "Because greenhouse gases fit well within the Clean Air Act's capacious definition of 'air pollutant,' we hold that EPA has the statutory authority to

regulate the emission of such gases from new motor vehicles."

Justice Scalia noted in a dissent that: "This court has no business substituting its own desired outcome for the reasoned judgment of the responsible agency."

In Environmental Defense Fund v. Duke Energy Corp., No. 05-848, 2007 U.S. LEXIS 3784, the Supreme Court endorsed EPA's interpretation of the Clean Air Act, holding that Duke Energy was required to have a permit before making substantial modification to coal-firing units. The U.S. Supreme Court agreed with EPA that a permit was required before Duke made modifications that did not increase the hourly output of emissions, but it allowed the generators to run for more hours per day, resulting in more output per year.

The Clean Air Act directs EPA to regulate air quality standards. Amendments in 1970 added the New Source Performance Standards (NSPS) program. Amendments in 1977 established a statutory Prevention of Significant Deterioration (PSD) program, which requires permits for certain "modifications." EPA's regulations under the PSD program focus on increases in annual emissions rather than hourly emissions when determining which "modifications" require permits. However, the NSPS definition has its focus on hourly emissions.

After respondent Duke Energy Corporation replaced or redesigned the workings of some of its coal-fired electric generating units, the United States filed this enforcement action, claiming, among other things, that Duke violated the PSD provisions by doing the work without permits. Duke moved for summary judgment, asserting, *inter alia*, that none of its projects was a "major modification" requiring a PSD permit because none increased hourly emissions rates. Duke argued that NSPS and PSD definitions must be the same.

EPA did not have authority to define PSD "modifications" based on annual emissions. The District Court entered summary judgment for Duke on all PSD claims and the Fourth Circuit affirmed. Environmental Defense and the government argued that the text of the statutes and the courts' duty to defer to EPA's regulations support the EPA's regulation. When the Fourth Circuit *sua sponte* requested supplemental briefing on the relevance of the Supreme Court's decision in *Rowan Cos. v. United States*, 452 U.S. 247, 250, the plaintiffs injected a new issue into the case. The plaintiffs argued that a claim that the PSD regulation exceeded statutory authority would be an attack on the validity of the regulation and must be brought only in the District of Columbia Court Circuit of Appeals, so the Fourth Circuit had no authority to hear the case. The Fourth Circuit rejected this argument, ruling that its interpretation did not invalidate the PSD regulations because they can be interpreted to require an increase in the hourly emissions rate as an element of a major "modification."

The U.S. Supreme Court reversed The Fourth Circuit's reading of the PSD regulations in an effort to conform them with their NSPS counterparts on "modification" amounted to the invalidation of the PSD regulations. The Fourth Circuit's construction of the 1980 PSD regulations to conform them to their NSPS counterparts was not a permissible reading of their terms. The PSD regulations clearly do not define a "major modification" in terms of an increase in the "hourly emissions rate." On its face, the definitional section specifies no rate at all, hourly or annual, merely requiring a "physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any" regulated pollutant. Even when the regulations mention a rate, it is annual, not hourly.

B. D.C. Circuit review sought for CAISO grid management charge

On March 29, 2007, the Cogeneration Association of California (CAC) and the Energy Producers and Users Coalition (EPUC) filed a petition for review in the DC Circuit requesting review of FERC's approval of CAISO's allocation of control area services component of the grid management charge to behind the meter generation. (FERC Docket No. ER01-313, *Order Accepting Unbundled and Amended Grid Management Charge and Grid Management Charge Pass-Through Tariff for Filing, Suspending Tariff Revisions, Consolidating Dockets and Establishing Hearing Procedures*, 93 FERC ¶61,337 (2000) and subsequent orders.)

On Nov. 7, 2005, the Commission issued an order addressing the allocation of CAISO's control area services (CAS) component of its grid management charge to behind the meter generation for the period Jan. 1, 2001 to Dec. 31, 2003. In approving the plan, the Commission found that CAISO had used appropriate models from participating transmission owners; conducted valid studies concerning transmission planning; and incurred costs from generating units, recovered by the CAS charge. 113 FERC ¶ 61,135. FERC also found that unmodeled behind the meter generation did not impose a CAS charge and asked CAISO to make a compliance filing to address deficiencies in the identification of generators that were modeled.

On Dec. 7, 2005, the Cogeneration Association of California (CAC) filed a request for rehearing, contending that the Commission was in error in finding that the only loads that should receive an exception from CAISO's CAS charges were those not modeled by CAISO and behind the meter. CAC's argument was that retail loads should also be

subject to the exception because they did not cause CAISO to incur costs other than when actually using the grid and claimed that the totality of the evidence supported this view. CAC took issue with FERC’s definition of the “excepted customers,” arguing that the definition was too narrow.

FERC denied the request for rehearing, rejecting the contention that the exemption as defined was too narrow. 116 FERC ¶ 61,224. According to FERC, the exemption was neither based on a preconceived idea nor was it inconsistent with its prior statements and was correctly defined.

On Oct. 10, 2006, the CAC and the Energy Producers and Users Coalition (EPUC) collectively filed another request for rehearing, making arguments similar to those they had raised before.

FERC again denied rehearing on Jan. 29, 2007. 118 FERC ¶ 61,061. The Commission stated that it does not allow parties to seek rehearing of an order denying rehearing in the interests of curtailing indefinite litigation. Only when an Order significantly modifies a prior Order will rehearing requests be entertained.

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