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## **ELECTRICITY LAW DEVELOPMENTS – January 11, 2006**

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. New inside this issue:

- **ELCON and numerous others comment on proposal to approve 83 of NERC's 107 reliability standards (p.2);**
- **Transmission pricing reforms to increase power grid investment: FERC reaffirms Order 679 in part and grants rehearing in part (p.5);**
- **FERC announces conferences to examine competitiveness of wholesale markets (p.10);**
- **FERC conditionally approves PJM Reliability Pricing Settlement (p.11);**
- **SPP tells FERC it is ready to launch EIS market next month (p.16);**
- **FERC announces technical conference on MMU policies (p.18);**
- **Ninth Circuit reverses FERC treatment of long-term power contracts in California (p.19)**
- **Alcoa files petition for review in DC Circuit on request for rehearing of allocation of ERO costs and cost benefit analysis standards discussed during NERC's ERO certification (p.24).**

New developments since the November 20, 2006 issue of Electricity Law Developments are in **bold**.

**I. FERC PROCEEDINGS**

**A. NERC Application for FERC Certification as National ERO  
Docket Nos. RR06-1, RM06-16**

**On December 1, 2006, NERC filed its “Reliability Standards Development Plan: 2007 — 2009” (Work Plan) with FERC. NERC stated that the Work Plan was submitted to inform the Commission of NERC’s program to improve the Reliability Standards that currently are the subject of the Commission’s October 20, 2006 NOPR. A portion of the Work Plan also is designed to fulfill the commitment NERC made in its April 2006 ERO certification application to provide the Commission with a plan to address the “fill-in-the-blank” regional reliability standards. The informational filing also contains a status report on the violation risk factors that NERC plans to assign to each requirement in its Reliability Standards to help delineate the relative risks associated with the violation of each requirement of a Reliability Standard. FERC asked for comments on the Work Plan to be submitted in conjunction with comments on the October 20, 2006 NOPR.**

***Background***

On October 20, 2006, FERC issued a notice of proposed rulemaking, stating its intention to approve 83 of 107 reliability standards proposed by the North American Electric Reliability Council (NERC), though modification of some of the standards will be necessary and will be ordered pursuant to a final rule. FERC decided not to rule on the 24 remaining standards at this time.

FERC also addressed three other issues:

(a) Definition of bulk electric transmission system: Whereas the industry and proposed standards define the nation’s bulk electric transmission system as network facilities of 100,000

volts or higher, the EPart 2005 is broader and excludes only “local distribution facilities”.

FERC attempts to resolve this by stating that during a transition period, the historical standards will be used while the ERO works on a standard consonant with the EPart.

(b) Interpretation of “user of the bulk power system”: FERC proposes to determine who a user of the system is on a standard specific basis in the context of the objective of the relevant standard.

(c) Discretion in considering violations: For the first six months after the new standards are established as mandatory, FERC, the ERO and REs are directed to use discretion in finding standard violations or assessing penalties.

ELCON and others had requested a rehearing or clarification of FERC’s July 20, 2006 Order certifying NERC as the ERO. On October 30, FERC denied rehearing.

**On January 3, 2007, FERC received numerous comments on the NOPR and on the December 1 informational filing by NERC. Not surprisingly, NERC was pleased with the Commission’s conclusion that the 83 standards are just and reasonable. Placing these standards into effect immediately, NERC stated, will allow it to “affirmatively mitigate any noncompliant performance of bulk power system owners, operators and users going into the summer of 2007,” and will “serve to create a solid foundation on which to improve and expand the standards ... without reopening for further debate the underpinnings of standards that have already been approved by stakeholders and utilized in practice by the industry.”**

**ELCON submitted comments generally supporting the Commission’s proposal to approve 83 reliability standards and designate 24 other standards as “good utility practice” pending further development. ELCON agrees that the Commission should rely on the**

**NERC standards process for further development rather than try to rewrite any standard but notes that improvements need to be made to address recommendations in the August 2003 Blackout Report. Second, ELCON recommends that the term “bulk-power system” as proposed by the Commission be the reliability-based definition currently used by NERC in its term “bulk electric system”. “Erring on the side of registering every potential ‘User of the Bulk-Power System’ will only distract the compliance staff at both NERC and the regions from concentrating their efforts on identifying and monitoring compliance of entities that are most likely to have a material impact” on system reliability. However, any entity reasonably deemed material to reliability should of course be registered and regional entities should have a role in identifying and registering such entities.**

**Among other industrial user groups commenting on the NOPR or Work Plan, the Process Gas Consumer Group echoed ELCON’s concern that users who have no material effect on reliability of the power system not be unnecessarily burdened and were also in favor of participation in demand response resources. Multiple Intervenors focused on the need to encourage demand response and eliminate unnecessary barriers to demand response participation in energy, capacity and ancillary service markets. To that end, they asked the FERC clarify the NOPR to provide express permission for technically-qualified loads to participate in all ancillary services markets.**

**EPSA noted the importance of balancing oversight with standards development. They supported FERC’s decision to conditionally approve “imperfect” standards subject to future modification of such standards. They encourage FERC to assure that standards are clear and unambiguous regarding what is required and who is required to comply.**

**EPSA expressed concern regarding FERC’s proposed “validation period,” suggesting that actual penalties might be imposed for violations by aggravated circumstances.**

**EEl similarly commented that enforcement discretion even during the trial period is “essential to the continued success of the program.” They stated that they “stand strongly for the principle that all responsible entities should comply at all times with Reliability Standards.” EEI also expressed concern that certain standards lacked technical features or specificity necessary to be clear and unambiguous. They question how FERC can find such incomplete standards to be just and reasonable.**

**APPA and NRECA filed comments suggesting that FERC had not satisfied obligations under the Regulatory Flexibility Act to analyze impacts on small entities, and cautioned that this failure could lead to judicial challenges of the standards. They state that FERC may have substantially underestimated the number of small businesses – including “hundreds, if not thousands, of small industrial facilities, small generators and small qualifying facilities that may also meet the small entity definition” -- that will experience significant economic impact. “Most such entities do not own facilities that have a material impact on the reliability of the bulk power grid in this country, yet the NOPR in its current state appears to contemplate that they would all be subject to NERC’s mandatory reliability regime.”**

**B. Transmission Pricing Reforms To Increase Power Grid Investment  
Docket No. RM06-4-000**

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Background

EPAct 2005 directed the Commission to develop incentive-based rate treatments for transmission of electric energy in interstate commerce. On July 20, 2006, FERC issued Order

No. 679 to establish incentive-based rate treatments for transmission, with the goal of encouraging investment in transmission infrastructure. Despite widespread criticism that the incentives are excessive, FERC made few changes from its November 18, 2005 proposed rule.

FERC explained its approach by noting that the Order merely identifies specific incentive rate treatments that *may* be approved by FERC. Applicants must meet the burden to justify proposed incentives on a case-by-case basis, and incentives must be in a “zone of reasonableness” and otherwise satisfy the existing FPA ratemaking standards.

In addition to incentive rates of return on new investment by traditional utilities and standalone transmission companies, Order No. 679 allows: recovery of 100 percent of prudently incurred construction work in progress costs, pre-commercial operation costs, and costs of abandoned projects if abandonment is outside of management’s control; accelerated depreciation recovery; recovery of costs to comply with mandatory reliability standards; recovery of costs to facilitate infrastructure development in National Interest Electric Transmission Corridors (NIETCs); and various other specified types of incentive cost recovery. However, although initially proposed, FERC decided not to adopt generic performance-based ratemaking incentives at this time.

Transmission entities seeking incentives may either submit a petition for declaratory order followed by a Section 205 application, which could pre-approve the incentives before construction to facilitate financing, or simply include the application for incentives in the Section 205 filing. Applicants for incentives must show that: (1) the facilities for which incentives are sought either ensure reliability or reduce congestion; (2) a nexus exists between the incentives and the investment; and (3) the resulting rates including the incentives are just and reasonable. However, FERC decided that the applicant need not show that the investment would not have

been made without the incentives. Further, in an expansion of the proposed rule, Order No. 679 establishes a rebuttable presumption that transmission projects approved through a regional transmission planning process, approved by a state siting authority, or located within a NIETC are eligible for incentives.

FERC rejected calls by ELCON and many other commenters to hold the granting of incentives to a cost-benefit standard. FERC made three points in its summary dismissal of cost-benefit analysis: (1) court decisions recognize that FERC may consider non-cost as well as cost factors in decisionmaking under the FPA; (2) Section 219 reflects a Congressional determination that incentives generally provide the benefits of spurring transmission investment; and (3) FERC will consider the justness and reasonableness of incentives in individual rate proceedings. ¶ 65.

Utilities receiving incentive rate treatment for specific transmission projects will have to file new FERC Form 730 by April 18 of each year. The report requires filing of actual transmission investment for the preceding calendar year, projected incremental investments for the next five calendar years, and project-specific information (including expected completion date, percentage completion, and reasons for any delays).

### Rehearing Requests

A wide range of 15 parties requested rehearing, including industrial customers, transmission-dependent utilities, public power, and EEI and its allies. Major issues raised on rehearing include the following:

- Incentives for RTO Participation. Several parties asserted that FERC does not have the statutory authority to give transmitting utilities incentives to remain in an RTO and in any event that incentives are unlikely to either encourage RTO participation or promote new transmission capacity.
- Nee for Incentives. The California and Connecticut commissions argued that FERC's finding of the need for ROE incentives to promote transmission was unsupported and

that, at a minimum, such incentives should not be granted where the utility is obligated to by law, or has entered a binding commitment, to build new transmission.

- **Scope and Level of ROE Incentives.** Most parties addressing the issue expressed concern that the ROE Incentives are excessive – that incentive ROE at the upper end of the zone of reasonableness will lead to rates of return that are arbitrary or too high. Industrial Customers opposed allowing a recipient to benefit from both incentive based ROEs and non-ROE incentives. On the other hand, Southern seeks incentives for existing as well as new transmission.
- **Nexus Requirement.** Industrial Customers and others asserted that the requirement of a nexus between the incentive and the investment is vague, urging particularized findings, cost-benefit analysis, and transparency.
- **Rebuttable Presumption.** Several parties challenged Order No. 679’s rebuttable presumption that investments meeting certain criteria are eligible for investment, asserting that there is no reason to assume that projects meeting the criteria will promote reliability and reduce congestion.
- **Corporate Structure.** EEI and others challenged the special incentive ROE and tax-related ROE granted to Transcos, asserting that they should be made available to others, while TDU Systems opposed giving the incentives to Transcos.
- **Public Power.** Representatives of public power seek conditioning incentives on a showing that the transmission owner sought financial participation by public power entities and participation in open regional transmission planning.

**On December 22, 2006, the Commission addressed these issues in Order 679-A, wherein the Commission largely reaffirmed Order 679, maintaining incentive-based (including performance-based) rate treatments for the transmission of electric energy by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing transmission congestion. 117 FERC ¶ 61,345.**

**Order 679-A modified the Final Rule as follows:**

- 1. To address NARUC’s concerns that FERC erred in rebuttably presuming that certain review processes (e.g., state siting approvals and regional planning processes) satisfy section 219's requirement that a transmission project ensure**

reliability or reduce congestion, the Commission granted rehearing in part on the issue. FERC agreed with NARUC to the extent that, if review processes do not include a determination of whether a project ensures reliability or reduces congestion, no rebuttable presumption should exist for that project. FERC will require that each applicant explain whether any process being relied upon for a rebuttable presumption includes a determination that the project is necessary to ensure reliability or reduce congestion. Furthermore, this rebuttable presumption will apply only to whether the project reduces congestion or encourages reliability, not the additional requirements of the Final Rule.

2. The Commission reviewed the Final Rule's nexus requirement between the incentive being sought and the investment being made. Several petitioners argued that the nexus test was not sufficiently rigorous to protect consumers. The Commission granted rehearing in part on this issue. The Final Rule stated that the nexus test was to be applied separately to each incentive, rather than to the package of incentives as a whole. FERC agreed that this approach fails to protect consumers where an applicant both seeks incentives that reduce the risk of the project and seeks an enhanced rate of return on equity (ROE) for increased risk. FERC will therefore require applicants to demonstrate that the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project. The Commission will apply a rule of reason with respect to what is sufficient to meet the requirement of "demonstrable" risk or challenge. An applicant may provide specific evidence of a risk or challenge or a supported

explanation of why it faces a particular risk or challenge. If some of the incentives in the package reduce the risks of the project, that fact will be taken into account in any request for an enhanced ROE.

3. In response to several concerns that the Commission will routinely grant an enhanced ROE at the top end of the zone of reasonableness, the Commission stated that it has broad discretion to establish ROE anywhere within the zone of reasonableness, but intended to be careful in the manner this discretion was exercised. The Commission clarified that each applicant will, first, be required to justify a higher ROE under the required nexus test and, second, to justify where in the zone of reasonableness that return should lie.

Although some investors might desire up-front certainty regarding ROE before they invest in a particular project. FERC's traditional ratemaking practice typically determines ROE in a hearing only after an investment is made and a facility is constructed and does not provide such up-front certainty. Therefore, the Commission clarified that it would entertain requests for a specific ROE determination in a petition for declaratory order.

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

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The Commission has announced that it will convene a series of public conferences to evaluate the state of competition in wholesale power markets. The first conference will be held on February 27 at FERC headquarters in Washington D.C. The conferences will 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 will address the challenges faced by all wholesale markets, including organized markets and bilateral contract markets.**

**Citing significant debate and concern about the costs and benefits of wholesale power markets, FERC says it plans to evaluate the various challenges faced by the different types of wholesale power market structures across the country, with an aim to strengthening the markets in all regions. These conferences will provide a forum for affected stakeholders – including state regulators, consumers, generation suppliers and transmission providers – to discuss the critical issues and identify potential solutions. ELCON and EPSA have praised FERC for recognizing the need to engage in formal discussion on the effectiveness of the power markets.**

**D. FERC conditionally approves PJM Reliability pricing settlement  
Docket ER05-1410**

**On December 22, FERC conditionally approved a settlement filed by PJM Interconnection, L.L.C. (PJM) and multiple PJM market participants concerning PJM's Reliability Pricing Model (RPM) to establish new market rules that will enable PJM to obtain sufficient energy to reliably meet the needs of consumers within PJM. 117 FERC ¶ 61,263. PJM's current market rules establish a single market for supply, but this structure does not assure that the supply is available to all local areas. FERC stated that based on the evidence supplied by the parties, the Settlement is expected to provide greater incentives for new generation, transmission, and demand response, while also providing sufficient revenues to retain existing resources that are needed. FERC also expects that**

**the overall cost of the settlement provisions will be less than what would be incurred under PJM's existing mechanisms.**

**Background**

On September 1, 2005, PJM Interconnection filed a proposed Reliability Pricing Model (RPM) to replace its current capacity market. In the filing, PJM states that the current structure of the capacity market does not assure that reliability will be maintained at the lowest reasonable cost: only short-term (daily and monthly) capacity markets are offered, each with widely varying prices. Under the RPM, a four-year forward contract would be available. Other features of the mechanism include a downward-sloping variable resource requirement curve, locational valuation of resources to address needs in load pockets; value attributed to resources needed for reliability and to those which can come on line within 30 minutes when needed; and capacity-market specific market power mitigation rules. PJM stated that many of the features it was proposing in its filing have already been approved by the Commission for other RTOs or ISOs. PJM distinguished its plan from the controversial ISO-NE LICAP mechanism in that the RPM provides for annual adjustments to the forward price "demand curve" through annual auctions that reflect current market conditions, and transmission and demand response resources will be permitted to bid in the RPM system. PJM had hoped to implement RPM by June 1, 2006.

On October 19, 2005 ELCON joined comments submitted by the PJM Industrial Customer Coalition ("PJMICC") and other industrials urging FERC to reject the proposal. The RPM filing, industrial consumers argued, is driven by PJM's expectation that reliability problems will develop in certain specific regions of its system because of the expectation of high rates of generation retirement in areas of high load growth with little new generation to be added. PJM "failed to prove that its current capacity market is the 'root cause' of any such localized

investment concerns in the PJM footprint. Nor has PJM demonstrated that RPM is a ‘just and reasonable’ solution to the isolated problems identified in PJM’s filing. RPM’s broad ‘one size fits all’ approach to solving a local issue is in direct violation of the Federal Power Act and inconsistent with Commission precedent, including the Commission’s fundamental expectation of the consumer benefits of electric restructuring.”

Characterizing the RPM filing as evidence of a serious crack in PJM’s foundation,

Industrials stated:

RPM’s introduction of a locational capacity component and an artificial demand curve to solve sub-optimal investment in discrete areas makes clear that ...LMP has failed to achieve the objective of ‘send[ing] price signals that are likely to encourage efficient location of new generation resources, dispatch of new and existing generation resources, and expansion of the transmission system.”

Furthermore, Industrials argued, PJM had not demonstrated that RPM signals would be any more effective or reliable for customers than LMP signals and the proposal ignored the need for additional transmission.

On April 20, 2006, FERC found that PJM’s existing generation capacity obligation rules are unjust and unreasonable and told PJM it agreed that they must be replaced. FERC indicated that certain elements of the proposed RPM might form the basis for a just and reasonable capacity market, but that these features need to be analyzed further before such a determination is made. In particular, FERC noted that the resulting market must encompass areas that best reflect the operational characteristics and transmission constraints of the PJM system, and ordered a paper hearing to determine how best to achieve this. FERC approved PJM’s proposed four-year forward procurement proposal, agreeing with PJM that the current daily and monthly procurement system should be replaced with a program that is more conducive to system

planning. However, the Commission set for hearing will be the duration of capacity

commitments. Additionally, FERC found:

- The capacity market must provide generation, demand response and transmission with reasonable opportunities to compete in resolving reliability concerns.
- A dual method of satisfying capacity obligations among which states and utilities can choose is appropriate. One method would involve the RPM capacity auction approach proposed by PJM. The Commission approved the use of a downward sloping demand curve in that auction, but set for technical conference the parameters of designing the curve. The other method of satisfying the capacity obligation would be to set fixed capacity requirements for load-serving entities. Certain parameters of this approach, including a meaningful deficiency charge for failure to meet reliability targets, would also be considered in the technical conference.

The plan must continue long enough for new generation entrants to recover their investment costs. The Commission found PJM's proposal to include energy revenues in determining the slope of its demand curve is a reasonable method of ensuring that changes in the energy market will be reflected in the capacity market.

**On September 29, 2006, PJM submitted a settlement agreement to FERC that purportedly resolved all outstanding issues between parties. On December 22, 2006, FERC conditionally approved the settlement. The key features of the new RPM that was accepted include:**

- **Determination of prices through use of a downward-sloping demand curve. This is a mechanism to price supply within each local area so that prices change gradually based on the balance between the amount of supply offered and the amount required for reliability. It encourages investment by increasing revenue stability over time. It also better indicates the incremental value of capacity at different capacity levels than the current mechanism, where prices change abruptly with small changes in supply around the reliability requirement. In addition, this mechanism is anticipated to reduce the incentive for sellers to withhold capacity in order to exercise market power by decreasing the potential to obtain excessive profits through market manipulation. Further, the settlement includes a provision under which qualifying utilities that prefer not to participate in this mechanism may choose instead to fulfill their own reliability responsibilities.**

- **Forward procurement.** Under the settlement, load-serving entities must make commitments to procure a sufficient supply of energy three years ahead, rather than the shorter term commitments that are common now.
- **Locational pricing phase-in.** The settlement provides that PJM will create 23 Locational Delivery Areas for the determination of prices, but that division of the market will be completed incrementally through delivery year 2010-2011, so as to allow time for market participants to realign their contractual obligations.

The major provisions of the Settlement are summarized as follows:

- **In order to assure that sufficient supply is obtained for local areas, the Settlement provides that each company providing electricity to customers throughout PJM is required to supply or purchase resources to provide sufficient electricity to meet the reliability targets for its service areas. The Settlement therefore creates separate areas (Locational Delivery Areas) within PJM, and requires that generation and transmission to those areas be sufficient to provide reliable service.**
- **The Settlement provides that utilities can supply their energy needs through a combination of generation, transmission, and demand response, including energy efficiency.**
- **Prices will be set in each area to reflect the needs of each area. The Settlement provides for prices to be set through an auction market with a demand curve that reflects the reliability value of increased supply. The demand curve is expected to decrease the volatility of the market and thereby create a better market environment for investment in new generation and retention of existing plants as well as in demand response programs. Utilities that prefer not to participate in the auction market and that meet certain other requirements may procure a pre-determined amount of supply outside the auction sufficient to ensure reliability for their customers.**
- **To increase the opportunities for competition from new entry, the Settlement provides that companies providing service to customers must contract with suppliers three years in advance to ensure that reliability goals are met and that current generators as well as new generators can be assured of sufficient revenues to either retain their current investment in PJM, or invest in constructing new generating units.**

The Settlement includes a number of design features that discourage the exercise of market power and market manipulation generally. Specific mitigation rules and increased competition from new entry are the most important design elements in this regard.

Additionally, since this market design is anticipated to decrease price spikes, it is likely to

provide fewer incentives for sellers to exercise market power by withholding supply from the market.

The settlement requires PJM to file changes to the provisions that discriminate between signatories and non-signatories to the settlement, removing the provisions granting discretion to the PJM Market Monitor and revising the tariffs to enable expedited cost recovery.

On January 8, 2007, PJMICC filed a notice of withdrawal from the settlement, citing concern with some of the conditions FERC had imposed. In particular, PJMICC stated that the expansion of the class of generation owners eligible to add Mandatory Capital Expenditures to otherwise applicable offer caps, the expansion of generation owners eligible for the “offer adder safe harbor,” and the requirement that PJM develop and file changes to the MMU’s authority “combine to add risk to customers in the PJM region that was not contemplated by the Settlement and that is not offset by customer-oriented benefits.” Portland Cement and a small number of others also filed notices of withdrawal citing similar concerns with FERC’s imposed conditions.

**E. SPP Real-Time Energy Balance Market**  
**Docket No. ER06-451**

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SPP on December 22, 2006, told FERC it will be ready to launch its real-time energy imbalance services market on February 1, 2007.

*Background:*

SPP received FERC approval as an RTO in October of 2004 (109 FERC ¶ 61,009 (2004), *order on reh’g*, 110 FERC ¶ 61,137 (2005)). At that time, FERC accepted SPP’s commitment to develop an imbalance market, including implementation of a real-time, offer-based energy

market that will be used to calculate the price of imbalance energy. The Commission also required SPP to provide a market monitoring plan, including market power mitigation measures that address market power problems in the spot market and a clear set of rules governing market participation conduct, with the consequences for violations clearly laid out. FERC had rejected SPP's original imbalance market proposal and mitigation and monitoring plan as inadequate and provided guidance concerning: (1) reliable and stable market operations; (2) market-based rates in the new market; and (3) mitigation and monitoring issues. 112 FERC ¶ 61,303(2005).

On January 4, 2006, SPP filed proposed revisions to its OATT, including further developments of its imbalance market and market monitoring and mitigation plan. On March 20, 2006, FERC rejected the proposal in part and conditionally accepted and suspended it on other parts, finding that the proposed tariff provisions require modification or elaboration before FERC will be able to determine whether its imbalance market is designed and monitored properly and is just and reasonable. In particular, as acknowledged by SPP in its filing, the plan lacks certain key elements including an external market monitor contract, new provisions for transmission loss compensation, standard market participant and reserve sharing agreement, and a plan to measure market readiness performance.

**In this latest filing, SPP states that it has “tested its market systems, tested its transition and reversion plan, trained necessary personnel and committed the required resources to ensure the launch of the market without compromising the reliability of operations in SPP’s service region.” SPP indicated that there remain a few elements of its market implementation plan that are still undergoing testing, but that none of these outstanding issues “poses and impediment to SPP’s ability to reliably operate the EIS market.”**

**SPP asks for FERC's expeditious consideration of certain matters still pending, including a number of market design proposals that were submitted but which FERC has not yet passed on.**

**F. FERC Announces Technical Conference to Review MMU Policies**

**In connection with a December 5, 2006 denial of rehearing of FERC's acceptance of certain PJM tariff revisions aimed at conforming PJM's market monitoring plan with FERC's Policy Statement on Market Monitoring, the Commission announced a forthcoming technical conference to review Market Monitoring Unit Policies. 117 FERC ¶ 61,263. FERC stated that the comments it received in connection with the PJM proceeding "indicate that entities who are regularly involved with or affected by the functions of MMUs are concerned about a range of issues and policies arising from the functions of MMUs. Commissioners Kelly and Wellinghoff indicated that among the issues they would like the conference to address are the possibility of establishing a code of professional responsibility for market monitors, the role of the MMU in assessing the impact on markets of demand response resources and whether ISO/RTO tariffs should include language to redress certain undesirable market behavior expeditiously, without referring the matter to FERC for investigation.**

## **II. COURT PROCEEDINGS**

### **A. Ninth Circuit reverses FERC treatment of long-term power contracts in California**

The Ninth Circuit issued two companion decisions on December 19 of considerable significance reversing FERC's treatment of long-term power contracts entered into by the California Public Utilities Commission and the California Electric Oversight Board at the time of the California energy crisis in 2001. See Pub. Util. Dist. No. 1 of Snohomish County v. FERC, 2006 U.S. App. LEXIS 31297 (9<sup>th</sup> Cir. 2006); Pub. Util. Comm'n of Cal. v. FERC, 2006 U.S. App. LEXIS 31140 (9<sup>th</sup> Cir. 2006).

These decisions emphasize, first, that the fundamental purpose of the rate authority that FERC exercises under the Federal Power Act is to protect consumers. This general language will be useful to ELCON advocacy in a variety of contexts. Secondly, the decision holds that FERC abdicated its statutory responsibility to assure that wholesale contract rates are just and reasonable (J&R) when the Commission decided that market-based rate (MBR) contracts are somehow pre approved because at the time MBR authorization is granted, FERC has determined that the contracts are in the public interest. FERC could not ignore that at the time the forward contracts at issue were entered into, their own Staff Report had found that the markets were dysfunctional. The court ruled that Mobile-Sierra cannot apply without determination that the challenged contract was initially formed free from the influence of improper factors, such as market manipulation, the leverage of market power, or an otherwise dysfunctional market.

The decisions are of considerable importance as FERC initiates a proceeding, prompted by ELCON and other allies, to revisit whether the wholesale markets are

functioning in competitive fashion.

The court emphasized that the FPA requires FERC to benefit consumers, and that benefit to consumers is the ultimate purpose of FERC's review of wholesale prices under Sections 205 and 206.

The court turned to a discussion of the standard of review of the challenged contracts, observing that the parties and some of the cases speak as if two alternative standards for reviewing wholesale electricity contract rates exist -- the statutory "just and reasonable" standard and the Mobile-Sierra "public interest" standard. The court found that there is a single general, standard for FERC's adjudication of contract challenges like the present one: whether the challenged contract is "just and reasonable." The question therefore cannot be not whether the Mobile-Sierra or the "just and reasonable" standard of review applies.

The original Mobile-Sierra cases, which arose in the context of sellers seeking relief from low-rate contracts, hold that lack of profitability alone is not a basis for deeming a contract unreasonable when the seller has agreed to the rate that proves unprofitable. The Ninth Circuit noted that at the time that Mobile-Sierra was adopted, FERC approved individual contracts, which the Commission does not do under the current market-based rate regime where it has pre-approved the seller on the basis that the seller has no market power. The market-based rate regime differs from the regulatory context present in the Mobile-Sierra cases in two material respects: (1) the *timing* of the agency's initial review has moved to a point *before* contract formation, and (2) the *substance* of that review no longer focuses on the *terms of the contract*. 2006 U.S. App. LEXIS 31297 at\*17.

The court applied a tripartite analysis in considering whether forward contracts entered into during the western markets crisis were just and reasonable.

*First*, the court considered whether the contracts were subject to Mobile-Sierra review. Since the contracts called for or were silent with respect to applicability of the Mobile-Sierra standard, the court agreed with FERC that as a contractual matter the Mobile Sierra standard could be applied.

*Second*, the court focused on whether FERC's process allowed for timely and effective review of rates. The court found that FERC's review did not pass muster. The court found that market-based rate authority *can* qualify as sufficient prior review to justify limited Mobile-Sierra review only "when accompanied by effective oversight permitting timely reconsideration of market-based authorization if market conditions change." Here, the fatal flaw in FERC's approach to 'oversight' is that "it precludes timely consideration of sudden market changes and offers no protection to purchasers victimized by the abuses of sellers or dysfunctional market conditions that FERC itself only notices in hindsight."

The court rejected FERC's contention that the loose oversight scheme of market based rates passed muster:

A hypothetical explains the dilemma with FERC's present "oversight scheme": Seller A receives market-based rate authority in Year 1. In Year 5, prices increase dramatically in short-term markets. Buyer B, needing to escape these markets, agrees to long-term contracts X, Y, and Z to buy wholesale energy from Seller A. Buyer B agrees to the contract terms because in a frantic market Seller A is one of the only suppliers willing to enter into a long-term contract, and Buyer B needs to ensure that its supply is able to meet the load required by its retail customers. In its next required quarterly report in Year 6, Seller A dutifully transfers the proper information about its rates to FERC. FERC -- perhaps reviewing contracts X, Y, and Z -- discovers that the assumption of a functioning market underlying its approval of market-based rate authority for Seller A does not accord with the rates being charged in forward contracts generally, or in those entered by Seller A in particular. FERC therefore revokes Seller A's market-based rate authority. FERC's action, however, will do nothing to reform those troubling contracts.

Under this regime, FERC has *no* opportunity to review whether contracts X, Y, and Z are just and reasonable before they are entered. As FERC itself recognizes, revocation of market-based rate authority in Year 6 in the above hypothetical can only provide relief for contracts prospectively. FERC applies the Mobile-Sierra presumption that long-term bilateral contracts will reflect just and reasonable rates, without *any* opportunity for initial review of the rates. This, according to the court, amounts to an abdication of FERC's statutory duty to provide rate revision when necessary to assure just and reasonable rates. The court noted that the facts of the western markets crisis match the hypothetical: in 2003, FERC revoked Enron's market-based rate authority prospectively, but subsequently denied Nevada Power's request to reform its contracts with Enron even though the contracts were made during the period of abuse.

The court does not deny that FERC may adopt a market-based rate regime "if sufficient safeguards are taken to provide for sufficient oversight." However, FERC cannot use the choice of the market-based rate regime and couple with it Mobile-Sierra to adopt a process that precludes ordinary rate review, including the propriety of a grant of market-based rate authority at the time the contracts become effective.

*Third*, the Ninth Circuit held that FERC erred by adhering to Mobile-Sierra without considering market conditions at the time the contracts were formed: "Mobile-Sierra cannot apply without determination that the challenged contract was initially formed free from the influence of improper factors, such as market manipulation, the leverage of market power, or an otherwise dysfunctional market." While FERC acknowledged its Staff Report that the western markets were dysfunctional, FERC failed to consider whether the influence of the spot markets on the forward markets reached a

level sufficient to raise the question whether two parties could negotiate a just and reasonable contract triggering the Mobile-Sierra presumption. FERC failed to consider whether the contracts in question were entered into in fully functioning markets as a prerequisite to whether Mobile-Sierra should apply.

The court found that FERC further compounded the error by applying Mobile-Sierra analysis taken from the context of low-rate challenges to high-rate challenges. In a *low rate* case like the Sierra/Papago context, the important “public interest” concerns relate to the selling utility’s solvency and assuring that under recovered costs are not recouped from other customers. In contrast in a *high-rate* challenge, the public interest requires that the consuming public not be required to pay a rate too high to fall within the zone of reasonableness.

The court ordered remand so that FERC would consider whether excessive rates were paid in each of these proceedings: Snohomish, where the challenged contract accounted for an 8% increase for retail rate payers over 2001 rates; Southern Cal Water’s rate increase of 38%; and Nevada Power, where although retail rates decreased after the contract was entered, this factor did not excuse FERC from considering the public interest as rates may have increased so high because of dysfunction in the spot market that consumers still paid more under the forward contracts than they should have. A similar ruling was issued in the California Public Utility Commission companion case.

ELCON will wish to emphasize thieserulings to FERC as it presses the Commission on the need to address dysfunctional markets. While the Ninth Circuit opinion is not dispositive in other circuits (outside of the West Coast) and other courts may or may not

adopt the same reading of the contours of the Mobile-Sierra test, it is not a precedent that FERC can ignore.

**B. Alcoa files petition for review in D.C. Circuit regarding allocation of ERO costs Case no. 06-1426; FERC Docket No. RR06-1-000**

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On July 20, 2006, the Commission certified NERC as the Electricity Reliability Organization (ERO) for the United States. Alcoa, Inc. did not seek rehearing of the certification, but in its request filed on August 21, 2006, sought rehearing on the issues of allocation of ERO costs and the rejection of a requirement that proposed reliability standards be subject to a cost-benefit analysis as part of the determination of necessity to achieve reliability. Alcoa argued that the Commission erred in disallowing its requests to:

- (a) require NERC to allocate costs on a net energy for load (NEL ) basis;
- (b) use the NEL methodology to allocate costs to load served by generation located behind-the-meter ; and
- (c) use a cost-benefit analysis as part of its standards development process.

FERC denied Alcoa's rehearing request on October 30, 2006. 117 FERC ¶ 61,126.

On December 29, 2006, Alcoa filed a petition for review of this matter in the D.C. Circuit.

There has been no significant court activity on this case yet.

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