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ELECTRICITY LAW DEVELOPMENTS – October 3, 2008

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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 July 2008 issue of Electricity Law Developments are in bold.

I. REGULATORY PROCEEDINGS

A. FERC Rejects RPM Buyers' Protest of PJM Transitional Capacity Auction Prices but Will Convene a Technical Conference (Docket Nos. EL08-67, ER05-1410)

On September 19, 2008, FERC issued an order dismissing the May 30, 2008 complaint by RPM Buyers alleging that PJM's Reliability Pricing Model ("RPM") produced unjust and unreasonable capacity prices for the delivery years governed by the first four RPM auctions. 124 FERC ¶61,276. FERC also announced that it would hold a technical conference in February 2009 to address certain issues raised in RPM Buyer's complaint.

RPM background

In 2006, the Commission ordered PJM to redesign its capacity market because the market revenues received by capacity providers were likely to be insufficient to sustain the continued and future investment in capacity resources, and therefore would have a negative effect on reliability. The Commission accepted certain elements of a proposal made by PJM to replace its existing capacity construct and ultimately accepted the RPM Settlement Agreement to establish a forward-looking locational capacity market.

The RPM design is based on three-year forward-looking, annual obligations for locational capacity under which supply offers are cleared against a downward sloping demand curve, also called the Variable Resource Requirement curve (the "VRR curve"). The VRR curve establishes the amount of capacity that PJM requires its LSE customers to purchase, and the price for that capacity, in each capacity zone (or "Locational Delivery Area").

The VRR curve is based on two parameters – the net Cost of New Entry ("CONE") and the Installed Reserve Margin. For each LSE, the Installed Reserve Margin is equal to a specified

amount of capacity above its forecasted peak load. This additional amount is determined by the PJM Board, and is intended to ensure the availability of sufficient capacity to assure reliability. Under the VRR curve, the price of capacity is equal to the net CONE for a new peaking unit when the amount of capacity to be supplied is one percent greater than the Installed Reserve Margin. Capacity prices may be higher in transmission-constrained Locational Delivery Areas. LSEs that are able to fully supply their own capacity needs can choose not to participate in the VRR-based auctions, and instead choose a long-term Fixed Resource Requirement option.

RPM provides for base auctions to be conducted every year to procure capacity three years in advance of the year in which the capacity will be provided. Generators, transmission providers and demand resources may make offers to supply capacity to PJM in those auctions. The RPM Settlement also established a four-year transition period with an accelerated schedule for the transition auctions for capacity delivery years through 2011 and a phase-in of the 23 Locational Delivery Areas. RPM also includes measures to mitigate the exercise of market power. If a seller is found to have market power, that seller's bid is capped in an attempt to replicate that seller's avoidable costs.

After the Commission approved RPM, several parties, including some of the RPM Buyers, petitioned for review of those orders. That appeal is currently pending before the DC Circuit.¹

The first base auction took place in April 2007 and procured capacity for the 2007-2008 Delivery Year. Since then, four more base auctions have been conducted. The most recent auction, the May 2008 auction for the 2011-2012 delivery year, was the first to procure capacity under a full three-year forward commitment.

¹ *Pub. Serv. Elec. & Gas Co. v. FERC*, No. 07-1336, *et al.* (D.C. Cir. filed Aug. 23, 2007).

PJM RPM Buyers' Complaint

RPM Buyers alleged that the transition period rates resulting from the first four base auctions are unjust and unreasonable. RPM Buyers asserted primarily that, during the transition period, “[t]he absence of price discipline provided by new capacity resources and the ability of existing resources to withhold some capacity within the RPM rules combined to produce capacity prices in the transition period that are not comparable to those that would be produced in a competitive market or determined under cost-based regulation.” RPM Buyers also stated that when the Settlement was filed, the Commission limited parties’ ability to challenge aspects of the Settlement by only permitting the creation of a limited factual record and by requiring allegations of specific instances of market manipulation before addressing the potential for that problem.

In particular, RPM Buyers argued:

- Little or no new capacity was offered into the transitional auctions and there was very little capacity at prices close to RPM clearing prices.
- Supply curves were steep and inelastic at the clearing point.
- Steep and inelastic administratively-determined variable resource requirement curves were set at the wrong levels using exceptionally conservative parameters.
- Because auctions cleared on nearly vertical segments of the supply curves, withholding of small amounts of capacity resulted in a substantial increase on prices.
- Mitigation provisions, such as must-offer requirements and avoidable cost offer caps for existing generation, included exceptions that created advantageous loopholes for suppliers to justify much higher offer prices than were expected or intended when the program was designed.
- Various PJM procedures and RPM provisions excluded some capacity, further reducing supply and increasing prices.

- Locational “price signals” were highly volatile and moved as a result of regulated transmission enhancements and supplier strategic conduct. Locational Delivery Areas changed from one auction to the next and new investment was not attracted to transmission-dependent areas. Additionally, PJM imposed a stringent non-standard resource adequacy requirement that raised LDA reliability requirements that, coupled with the steep supply and demand curves, increased prices significantly.

ELCON, echoing concerns raised by RPM Buyers, filed comments arguing that PJM’s RPM transition auctions have failed to achieve any of the stated objectives of the RPM mechanism to send proper signals regarding the value of capacity by location through the introduction of a locational element in the capacity market, encourage the entry of new and additional resources, and reduce price volatility and the potential for market manipulation. Instead, customers in PJM have experienced sudden dramatic price spikes, market mitigation was required in every zone to address the lack of competition, and the new resources that the incentive payments were supposed to attract were unable fully to participate in the auctions.

In answers and protests, PJM and others asserted that the RPM Buyers’ complaint is an impermissible collateral attack on previous FERC orders because the complaint raised claims that relate to issues (locational pricing, transition auctions, the VRR curves, and market mitigation) already decided by the Commission. They argued that RPM Buyers had not presented new evidence or circumstances regarding those issues. PJM further noted that the RPM Buyers offered no better solution to the PJM capacity shortage, while other intervenors pointed out that some of the complainants had signed, or at least did not oppose the Settlement, therefore FERC should reject attempts by signatories to seek new opportunities to undermine the principles set forth in such an agreement.

RPM Buyers responded that the Commission reserved the right to make changes to the RPM Settlement when it stated that “PJM’s market participants may and should act to

address deficiencies that they see in PJM’s capacity markets, whether through PJM stakeholder processes or through seeking relief from the Commission.”²

FERC’s September 19 Order in Docket No. EL08-67

FERC rejected RPM Buyers’ claims, citing insufficient basis to re-run the past auctions or to change the prices resulting from those auctions.

The purpose of the auctions during the transition period was to establish capacity prices for those years leading up to the implementation of the full three-year-ahead auctions established under RPM. The prices and obligations set in those auctions became set as of the date of the auctions, and PJM and the capacity resource providers had every right to rely on those prices and obligations in making their decisions, including any capacity commitments and investment decisions. RPM Buyers have not established that any such investments were not, in fact, made. But even if resource providers had not yet made new investments in plant and equipment as a result of those auctions, each supplier of necessity would have had to forgo other opportunities to use its generating capacity, as a result of its commitment to serve PJM at the rates established in the auction. Indeed, capacity resource providers that participated in the transitional auctions gave up the opportunity to use their capacity to make bilateral sales of capacity or to participate in other RTO capacity markets.

FERC also found that RPM Buyers failed to show that any seller violated the mitigation rules in place during the auctions. Potential defects in tariff provisions are “issues that can be raised in the context of challenges to future auctions, but do not justify overturning the results of past auctions, including the commitments of generators to provide capacity and the commitments of PJM to pay for that capacity at the auction-determined prices.”

With respect to its statement encouraging parties to seek relief if deficiencies were noted, FERC stated that “the Commission was not suggesting that the rates for past

² December 22 Order, 117 FERC ¶ 61,331 at P 147.

auctions were tentative. The Commission merely reminded the parties of their right to raise concerns about and seek prospective review of potential market deficiencies.”

FERC’s September 19 Order in Docket No. ER05-1410

At the same time, in response to a related motion by RPM Buyers, FERC ordered a technical conference to assess the performance of RPM and directed PJM and its stakeholders to evaluate the design of the RPM with the intention of making changes on a prospective basis. The order summarizes the findings of the Brattle Report and recognizes PJM’s commitment to complete a “stakeholder review process” in time to make changes to RPM before the next Base Residual Auction scheduled for May 2009.

In particular, the Commission urged PJM to address the following issues:

- (1) Use of historical averages of energy and ancillary services revenue offsets to determine Net CONE. (The Commission stated that this is of “critical importance to RPM and that the methodology for determining offsets and consideration of different types of generation technologies for different LDAs, requires thorough review and refinement.)
- (2) Rules for the participation of energy efficiency and demand-side resources in the RPM auctions. (The Commission stated that by December 2008 it expects PJM to develop and implement provisions to enable energy efficiency resources to participate in the RPM auctions and to reflect such capacity resources in its load forecasts.)
- (3) Market power and mitigation rules. (The Commission stated that PJM should specifically address (a) calculation of avoidable costs, (b) effectiveness of the RPM mitigation rules, and (c) application and enforcement of RPM mitigation rules.)
- (4) Reliability requirements/criteria and defining Locational Delivery Areas. (The Commission stated that PJM should consider (a) loss of load expectation criteria; (b) the basis for defining LDAs electrically rather than on a service area basis, and (c) rules pertaining to incremental auctions and changes in LDA import capability.)
- (5) Must-offer rules relating to exclusion of capacity due to (a) the sales cap imposed on Fixed Resource Requirement entities and (b) partial year ownership and availability. (The Commission noted that such changes

are likely to reduce the magnitude of excluded capacity, lower RPM clearing prices, and increase system reliability in the short term.)

- (6) Performance penalties. (The Commission noted that penalties should be closely matched to capacity resource performance.)
- (7) Incremental auctions.
- (8) Length of forward commitment for new capacity resources.

To the extent that the PJM stakeholder process reaches agreement on these issues, the Commission “strongly encourage[d]” PJM to file revised tariff sheets by December 15, 2008, with an effective date of February 1, 2009. Also by December 15, 2008, PJM is to file a report containing “detailed explanations” for why any of the listed changes were not or could not be made, with a description of future plans to address the issues, or why the changes were determined to be unnecessary. In a forthcoming order, FERC will set the schedule and identify the issues to be addressed in a technical conference in February 2009.

B. FERC Terminates Another PURPA Mandatory Purchase Obligation but Declines to Define “Competitive Market” (Docket Nos. QM07-5; QM08-4)

In two decisions in July, FERC elaborated certain factors it will consider in reviewing requests for relief from PURPA’s mandatory purchase obligations.

Dominion Virginia Power, 124 FERC ¶61,045 (Docket No. QM08-4)

On July 17, 2008, over the protest of Smurfit Stone, FERC granted Dominion Virginia Power’s request to terminate its PURPA mandatory purchase obligations. Smurfit, the only one of the 18 QFs potentially affected by Dominion Virginia Power’s application to protest, operates a 41.5 MW cogeneration facility. Smurfit argued that it is unable to fully participate in the PJM markets because the timing and quantity of its output is determined by the operating schedule of its thermal host, and because its interconnection is inadequate to

accommodate the facility's full output. FERC rejected the arguments on the basis that they were too vague and because some of the factors Smurfit pointed to – such as the size of its interconnection – were in fact within the control of the QF.

FERC acknowledged that variable output is one factor it considers in relation to whether a facility has adequate market access; in the case of Smurfit, there was insufficient evidence before the Commission to show how the variable output rebuts the presumption of nondiscriminatory access. In order to rebut the presumption, FERC stated:

We expect a QF to provide a detailed explanation, and actual data on past experience, of how the QF's operational characteristics effectively prevent the QF's participation in the market. ... As part of that demonstration, as in this case, it is not adequate to merely claim that the electrical output of a facility may vary over time or with the changes in the operation of the thermal host.

FERC specified that “information about the nature, degree, volatility, unpredictability, suddenness, frequency and/or other characteristics of site-specific operational conditions should also be coupled with an explanation as to how these circumstances prevent effective participation in the particular market at issue, citing to relevant market design features.”

Xcel Energy Services, et al., 124 FERC ¶61,073 (Docket No. OM07-5)

In January 2008, FERC granted Xcel Energy's application to terminate its PURPA mandatory purchase requirements in the Southwestern Power Pool region (SPP) with respect to Oklahoma Gas and Electric Company (OG&E) and American Electric Power Service Corporation (AEP), but denied with respect to Southwestern Public Service Company (SPS). 122 FERC ¶61,048. Commissioners Kelly and Wellinghoff had issued dissents to the decision stating that applicant had not demonstrated that SPP has competitive wholesale capacity and

energy markets or that QFs have a meaningful opportunity to sell in those markets to buyers other than the utility to which the QF is interconnected.

Xcel requested rehearing with respect to SPS and asked FERC to clarify that the SPP market satisfies the PURPA 210(m)(1)(B)(ii) standard as to the entire SPP footprint. Xcel asserted that although FERC did not make this specific finding in its January 2008 decision, it must have implicitly found the market to satisfy the statutory criteria in order to reach the question of transmission access. A number of protestors intervened, urging FERC to deny both of Xcel's requests. Additionally, several asked FERC to reverse its determination granting relief to OG&E and AEP, requesting FERC to define or describe the key terms in the statutory test under PURPA such as "competitive" and "meaningful opportunity".

On July 21, 2008, the Commission (by a 3-2 vote) denied all rehearing requests. After denying Xcel's request for rehearing of the denial of relief for SPS (without prejudice), FERC confirmed that its January decision did not constitute a generic finding that SPP's markets meet the PURPA requirement for a "competitive wholesale market that provides a meaningful opportunity to sell capacity ... and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the [QF] is interconnected." Rather, the decision was a determination that the QFs in the SPP service areas of OG&E and AEP have access to such markets.

FERC also expressly declined to further define the statutory terms:

In making its finding, rather than focusing on individual components of section 210(m)(1)(B)(ii), the Commission looked to the relevant phrase as a whole. The Commission is not required to individually define every word. Rather, it is appropriate in these circumstances that the Commission read and apply the entire phrase, where the meaning of the phrase can be more than the meanings of the individual words. By its nature, any definition of "competitive" would either be so vague as to allow for too wide a range of markets to

fall under its umbrella or so specific as to reject too many markets for failing to meet every letter of the rule. Instead, the Commission reviewed the totality of the evidence provided and found that Applicants provided sufficient evidence to demonstrate that QFs and potential QFs in [the relevant] service territories have access to competitive wholesale markets that provide a meaningful opportunity to make sales to third party buyers.

FERC went on to note that market liquidity, opportunities for sales by QFs and entities like QFs, and other various kinds of evidence are examples of measures of competitiveness that it would consider. However, the Commission stated that it “sees no value in adopting a single definitive test for a competitive market.”

FERC also rejected arguments that it had treated the test for Day 1 markets as identical to that for Day 2 markets. Utility applicants in Day 2 markets, FERC said, are not required to present any evidence of sales by QFs or other generators or any evidence of the competitive nature of the market. Utility applicants from MISO, PJM, ISO-NE and NYISO “may rely on the rebuttable presumption that utilities in those regions should be relieved from the obligation to enter into new obligations or contracts to purchase from QFs larger than 20 MW.” In contrast, applicants in Day 1 markets are required to proceed on a case-by-case basis and are required to submit evidence to support the very different criteria contained in section 210(m)(1)(B) of PURPA.

Commissioners Kelly and Wellinghoff again dissented from the majority decision. Each reiterated the belief that the statutory criteria had not been met for relief to be granted to OG&E and AEP. Additionally, Commissioner Kelly strongly dissented from the Commission’s reasoning for refusing to define “competitive markets”:

In its January 22 Order, the Commission lists facts presented by the Applicants that it believes were unrebutted. . . . [I]t is important to point out that an agency cannot support an action based solely on a simple list of findings of facts and conclusions of law. The agency’s findings and conclusions must be linked to the action it takes through

a chain of reasoning. The Commission has not done that here. Instead of providing reasoning connecting the facts to the law and the relief granted, the Commission merely seeks refuge in the assertion that “on balance the evidence supported a finding” in favor of Applicants, and the conclusion that “we found that Applicants’ evidence was more persuasive.” Instead of explaining how it interprets section 210(m)(1)(B)(ii)’s standards regarding competitive markets, it avers that “any definition of ‘competitive’ would either be so vague as to allow for too wide a range of markets to fall under its umbrella or so specific as to reject too many markets for failing to meet every letter of the rule.” This unreasoned, “trust me” approach to decision making is simply not in accordance with law.

As was implicitly invited by the strong dissent, one of the affected QFs has filed a petition for judicial review of FERC’s order with the U.S. Court of Appeals. *John Deere Renewables, LLC. v. FERC*, No. 08-1306 (D.C. Cir. filed Sept. 19, 2008).

C. State Utility Regulators Protest Exclusion from Enforcement Proceedings (Docket No. RM08-8)

On May 15, 2008, FERC issued a NOPR proposing revision to rules applicable to *ex parte* communications and separation of functions in the context of non-public enforcement investigations (“Part 1b investigations”) and providing for release of annual statistical reports summarizing the Commission’s enforcement activities. By regulation, information obtained by staff during the course of a “Part 1b investigation” is considered non-public until such time as the Commission determines that disclosure is appropriate, or until disclosure occurs during an adjudicatory proceeding or pursuant to a FOIA request. Part 1b investigations therefore differ from other types of investigations carried out by the Commission, such as investigations into the justness and reasonableness of the rates in a particular market. Investigations that are not carried out under Part 1b generally are announced publicly, and include public comment and the maintenance of a public record in the same manner as adjudicatory proceedings.

Intervention

The NOPR proposes to clarify that the rule on intervention is not available as of right in proceedings arising from non-public investigations. Reasoning that restriction is necessary to prevent intervening parties from complicating or delaying an enforcement proceeding or sidetracking it from its purpose, the NOPR proposes that “once an enforcement proceeding is established, intervention should not be available except under limited circumstances” such as where a third party wished to determine the impact of a sanction of other resolution upon its own interests. NOPR at P 15 and 16.

Numerous state regulators and NARUC have voiced objections to the Commission’s attempt to prevent their intervention in such proceedings. NARUC stated that to the extent the proposed revisions seek to “eliminate a State Commission’s ability to join as a party to such proceedings via filing a notice, it is poor policy and inefficient – as well as inconsistent with the special role both Congress and Courts have accorded FERC’s State colleagues.” Moreover, they argue, Section 308 of the FPA authorizes FERC to admit a state commission as a party to any proceeding in which the state is interested. 16 U.S.C. § 825g(a). The section contains no qualifiers regarding the type of proceedings in which a State may intervene. “States are not just another stakeholder,” NARUC argues. “They, like the FERC, are public servants charged with overseeing the operations of regulated entities in the public interest.... Affected states should be parties as a matter of right in all FERC enforcement cases.”

Munis and co-ops, among others, have also protested the proposed rule change, arguing that participation should be allowed when an intervenor demonstrates that

sufficient interests are at stake and that participation would not unduly delay or complicate the proceedings.

Ex Parte Contacts

The NOPR also proposes to revise rules limiting contact with Commissioners and decisional staff in Part 1b investigations, with respect both to outside parties and to investigation staff. Commission investigative staff would have unrestricted access to FERC Commissioners and other FERC staff until a “show cause” order is issued; however the target of the investigation would be limited to communications with other FERC staff in writing.

EEI and EPSA filed joint comments arguing that the target should have the same communications opportunities as investigative staff; otherwise, the target “is at a distinct disadvantage in making its case to decisional employees.”

D. FERC Expands Blanket Authorization for Public Utility Dispositions to Non-Holding Companies; Clarifies Other Rules (Docket No. RM07-21)

In February 2008, FERC issued Order No. 708 to provide for additional blanket authorizations under FPA section 203 to facilitate investment in the electric utility industry and to ensure that public utility customers are adequately protected from adverse effects of such transactions. Order No. 708, 122 FERC ¶61,156. These authorizations included expanded blanket authorization for a public utility to transfer its outstanding voting securities to certain holding companies, including entities that are holding companies only through ownership of EWGs, QFs or FUCOs, holding companies regulated by the Board of Governors of the Federal Reserve Board or by the Comptroller of the Currency, and holding companies conducting certain underwriting activities or engaging in hedging transactions, among others. In general, blanket

authorization is granted if, after the transfer, the holding company or any of its associate or affiliate companies in aggregate will own less than 10 percent of the outstanding voting interest of the public utility. Additionally, blanket authorization may be granted for acquisition or disposition of a jurisdictional contract where neither the acquirer nor transferor has captive customers or owns or provides transmission service over jurisdictional transmission facilities, the contract does not convey control over the operation of a generation or transmission facility, the parties to the transaction are neither affiliates nor associate companies, and the acquirer is a public utility.

On July 17, 2008, FERC issued Order 708-A, 124 FERC ¶61,048, further expanding these authorizations to include disposition of utility interests to non-holding companies if, after the transfer, neither the acquirer nor any of its affiliates or associate companies will own more than 10 percent of the outstanding voting interests of the public utility. FERC stated that in the case of non-holding companies, however, it will adopt a new reporting requirement. FERC asked for comments on the type of information it should require and the timing of such reporting and ruled that the expanded blanket authorization would not become effective until FERC takes action on reporting.

FERC also modified its previously-issued blanket authorization with respect to the transfer of jurisdictional contracts, removing the prohibition on transactions between associate or affiliate companies. FERC explained:

...[W]here neither the acquirer nor the transferor has captive customers or owns or provides transmission service over jurisdictions transmission facilities, and the contract does not convey control over the operation of a generation or transmission facility, the price of the jurisdictional contract's transfer does not affect the rates of captive customers or transmission customers and therefore has no rate or cross-subsidization impact affecting captive generation customers or transmission customers.

Finally, FERC clarified that blanket authorization of an internal reorganization that does not affect a traditional public utility (e.g., a transfer of assets from one non-traditional utility subsidiary - such as a power marketer, EWG or QF – to another non-traditional utility subsidiary) is granted when only one of the two non-traditional utility subsidiaries survives the transaction. Because market power is analyzed on an aggregate or corporate family basis, FERC reasoned that such a transaction would have no adverse effect on competition.

Also on July 17, 2008, FERC announced certain clarifications to its cross-subsidization rules on affiliate transactions (Order No. 707, 122 FERC ¶61,155; Order No. 707-A, 124 FERC ¶61,047). In particular, FERC stated that affiliates within a single-state holding company system that does not have a centralized service company may provide each other general administrative and management services at cost, as long as they do not provide such service to entities outside the holding company. Additionally, FERC clarified that regulations pertaining to sales of non-power goods and services do not apply to fuel purchases covered by the Commission’s fuel adjustment clause regulations.

II. COURT PROCEEDINGS

A. Challenge to FERC’s PURPA Sec. 210(m) Implementation Rules (U.S. Court of Appeals for the D.C. Circuit, Case No. 07-1328)

In August 2007, the AF&PA filed a petition for review in the D.C. Circuit challenging FERC’s final rule implementing PURPA Section 210(m), which establishes the procedures and conditions under which a utility may seek relief from PURPA mandatory QF purchase obligations. (Order Nos. 688, 117 FERC ¶61,078 (October 20, 2006) and 688A, 119 FERC ¶61,305, (June 22,

2007).) In particular, AF&PA challenge FERC's rejection of the notion that a QF had to have nondiscriminatory access to a *meaningfully competitive market* in order for a utility's QF purchase obligation to be terminated. In a key passage in the rehearing order, FERC asserted: "Congress could have stated a broad general finding to be made by the Commission such as 'workably competitive markets.' Instead Congress tailored subparagraphs (A) and (B) to establish criteria specific to each market design...". Order No. 688-A at para. 47. "While it is true that EPACT 2005 did not repeal PURPA or the Commission's obligations to encourage QF development, enactment of section 210(m) of PURPA clearly changes the rights of QFs under PURPA. The Commission has no discretion other than to terminate the purchase requirement if it finds that a QF has nondiscriminatory access... . It would be inappropriate for the Commission to ignore this mandate... in a way that undermines the specific standards of relief that Congress chose to establish in the statute." *Id.*, at para. 48.

FERC stressed most heavily the different standard that Congress applied in Section 210(m)(1)(B)(ii) which requires a finding of access to "competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy including long-term, short-term and real tie sales." Such language is not contained in (A)(ii) which only requires access to markets. Even if Day 2 long-term markets are nascent, Congress in (A)(ii) only required that the Commission find that they exist, not that they be robust. Without much rationale, FERC also found that the one-year term used for EQR reports is sufficient to meet the statutory requirement that there be "wholesale markets for long-term sales of capacity and energy" within the meaning of section 210(m)(1)(A)(ii). Order No. 688-A at paras. 24-28.

AF&PA asserted that FERC's reading of 210(m) with respect to the Day 2 markets is inconsistent with the plain language of the statute that all markets must be competitive and is

untenable when viewed in the context of the other parts of 210(m), including the standards for utility relief in (m)(3) and for QF relief in (m)(4). AF&PA argues that FERC’s reading of the statute is nonsensical - Congress could not have intended for meaningless, noncompetitive markets to meet the statutory definition:

The Commission’s interpretation makes nonsense out of key pieces of the Statute. If meaningless, noncompetitive markets are enough to meet the requirement of §210(m)(1)(A)(ii), then §210(m)(1)(C) – which requires markets “of *comparable competitive quality* as the markets described in paragraph (A) [which the Commission believes may be meaningless and noncompetitive] and (B) [which must be “competitive” and feature a “meaningful opportunity to sell”] – is incoherent. If meaningless, noncompetitive markets are enough under §210(m)(1)(A)(ii), then §210(m)(3) - requiring utilities seeking relief from the Mandatory Purchase Obligation to “set forth the *factual basis* upon which relief is requested and describe why the conditions set forth in subparagraphs (A), (B) of (C) of paragraph (1) of this subsection have been met” – is likewise deprived of significance, since under the Commission’s interpretation of the term “markets” there is no factual basis upon which a QF could demonstrate that the markets required under (A) do not exist. Under the Commission’s interpretation §210(m)(4), which again requires a “factual basis” for concluding that the requirement of (A)(ii) is met, suffers the same incongruous fate.

The primary argument of FERC’s brief is based on strict statutory construction and deference to administrative agency interpretation of the statute. FERC asserts that, under the statute: (a) the Commission is not required to examine the competitive quality of the wholesale markets in the context of RTO markets because the word “competitive” is absent from the text of the statute; and (b) the test for whether a QF has nondiscriminatory access to a market is satisfied in the context of Day 2 markets because bilateral long-term contracts exist in these markets and QFs *have access* to buyers and sellers for long-term contracting purposes in all Day 2 regions because these markets operate under OATTs.

In its August 13 reply brief, AF&PA argues that FERC has missed the point -- that the failure to examine the competitive quality of the market in question not only is a misreading of the PURPA rules but also amounts to a deprivation of the procedural rights granted to QFs under the statute. A QF can have nondiscriminatory access under a utility's OATT; however if the market is not competitive, such access is meaningless. While FERC essentially argues that Congress presumed the Day 2 markets to be competitive, AF&PA assert that this is not necessarily the case, and that at any rate, FERC must on a case-by-case basis evaluate each application for relief in terms both of nondiscriminatory access *and* competitive quality of the market.

The briefing on burden of proof highlights the different positions of the litigants. According to FERC, if the QF is able to rebut the presumption that the RTO's OATT affords it nondiscriminatory access, the mandatory purchase obligation will continue. AF&PA replies that, to the contrary, under the statute it is up to the specific utility to furnish the factual demonstration that the statutory requirements are met; Congress did not place the burden on the QFs to show that the requirements are not met.

In May 2008, ELCON filed a brief as *amicus curiae* in support of AF&PA. ELCON's arguments focused on two issues relating to long-term contracting. First, ELCON asserted that FERC erred as a matter of law in concluding that the mere existence of the so-called "Day 2 markets" where there is any evidence of long-term contracting activity satisfies the statutory standard of *non-discriminatory access to long-term* contract opportunities. Second, ELCON argued that FERC erred in defining "long-term" contracts for purposes of section 210(m) as those with a duration as short as one year, based merely on selective reference to inapposite FERC precedent. In the absence of a statutory definition for "long-term contracts" or legislative

history, FERC should be guided by the purpose of section 210(m), which was not to remove incentives to QFs - important as they are to the electricity grid and achievement of improved energy efficiency - but rather to establish conditions whereby the deregulated wholesale markets can properly serve as a reasonable substitute for the mandatory purchase obligations of PURPA that would otherwise apply.

FERC's brief urged the Court to ignore ELCON's arguments as issues not properly before the Court because AF&PA did not challenge the definition of "long term".

However, FERC again justifies its selection of a one-year duration based on its treatment of power sales with a contract for more than one year as long-term for reporting purposes and under OATTs.

Oral argument has been scheduled for the morning of November 13, 2008, before Judges Garland, Brown and Williams.

B. The *Mobile Sierra* Doctrine Remains Before the Courts

For the first time in over five years, FERC (by a 3-2 vote) has asked the DC Circuit for rehearing *en banc* of a decision of that court, *Maine Public Utilities Comm'n v. FERC*, 520 F.3d 464 ("*Maine PUC*"). Although the *Maine PUC* decision affirmed FERC's approval of a multi-party settlement related to the ISO-NE's forward capacity market, the D.C. Circuit criticized as "extra-statutory" FERC's reliance on a "public interest" test under the *Mobile-Sierra* doctrine, rather than the "just and reasonable" standard, in reviewing a challenge brought by nonsettling parties.

In seeking rehearing, the Commission asserts that the D.C. Circuit's discussion of the *Mobile-Sierra* doctrine conflicts with the Supreme Court's subsequent decision in *Morgan Stanley Capital Group Inc. v. Pub. Util. Dist. No. 1 of Snohomish County, et al.*, 128

S. Ct. 2733 (June 26, 2008) (“*Morgan Stanley*”) and in particular its finding that the “public interest” criterion under *Mobile-Sierra* is not “extra-statutory,” but rather is a definition of what it means for a contract rate to satisfy the just and reasonable standard. Accordingly, a party must establish that a mutually-agreed contract rate seriously harms the consuming public for the Commission to overturn it as unjust and unreasonable.

The Commission also asserts that the two disparate decisions create an anomalous situation whereby FERC, acting on a complaint filed by a non-consenting party, has greater ability under the FPA to change an agreement than it does when acting on its own motion for the benefit of non-intervening third parties.

In an unusual move, Commissioners Wellinghoff and Kelly issued an opposing argument to the rehearing request. In their view, there is no conflict between the two decisions because the contexts were very different. The type of bilateral wholesale power contract at issue in *Morgan Stanley* is “a private contract that is negotiated in the marketplace, outside the ambit of the regulator.” By contrast, the agreement at issue in *Maine PUC* was a “contested settlement agreement addressing a utility’s voluminous, complex proposal to revise its tariff substantially” and is not an agreement “between two sophisticated actors playing on a level field.” They state:

There is ... no good policy reason to justify allowing the Commission to hold a settlement agreement to any standard other than the ‘ordinary’ just and reasonable standard. Indeed, such a holding would result in imbuing private parties with regulatory authority heretofore reserved to the Commission; would cause untold uncertainty in future adjudications before the Commission; would be unduly discriminatory to applicants for tariff changes who do not obtain settlement agreements; and would result in a regulatory morass of utility tariff provisions with differing status.

...

If tariff provisions that have been established through settlement agreements have a special status different from the status of [other]

tariff provisions, any process undertaken to reform these tariff provisions will be an exercise in combing through haystacks to determine which of the tariff provisions get special treatment and which do not.

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