

*Eight Issues, Eleven Minutes Per Issue*  
**An Overview of Federal Electric Law Developments**

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**NARUC Electricity Committee**  
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**I. Market Power**

- A. Utility Purchased Power Agreements [HR]
- B. Affiliate Asset Transfers [SH]
- C. Acquisition by Utility or Affiliate of Independent Generator [HR]
- D. Change in Corporate Status of Market-Based Rate Recipient [SH]
- E. Supply Margin Assessment [HR]

**II. Regional Transmission Organizations**

- A. Role of RSC in the RTO [SH]
- B. Recent RTO Approval Decisions HR]
- C. State Commission Access to RTO Market Data [SH]

## UTILITY PURCHASED POWER AGREEMENTS

### **PL04-6: Solicitation Processes for Electric Utilities**

#### ***Market Power Issues:***

- Generic Rulemaking addressing proposals for best practice competitive solicitation methods.
- Addressing market power concerns over potential affiliate abuse in the awarding of PPAs.

Issues posed:

- 1. Is the Commission's Edgar policy adequate to ensure that the most competitive power procurement choice is being made by utilities when affiliates are involved? Should the policy include a requirement for a competitive solicitation? If so, how should the solicitation be designed?**

*Edgar* identifies three means to demonstrate lack of affiliate abuse, each of which is inferior to a structural remedy:

- 1) *Evidence that the affiliate has won a formal solicitation or informal negotiation “designed and implemented without undue preference for the affiliate.” Edgar, 55 FERC at 62,168-9.*
- 2) *Evidence that the utility has agreed to pay prices in line with “prices which nonaffiliated buyers were willing to pay for similar services.”*

As FERC noted in *Edgar*, this evidence “is credible only to the extent that the nonaffiliated buyers are in the relevant market as the purchaser, and are not subject to market power by the seller or its affiliates.” *Id.*

- 3) *“Benchmark evidence” showing the the prices, and terms and conditions of sales made by nonaffiliated sellers. Id.*

- 2. To the extent you have been involved in solicitation processes to date:**
  - **Please briefly describe the product solicited (e.g., power purchase agreement, dispatchable asset-backed contract, firm load-following power).**
  - **Was the competition on price only or also non-price factors?**
  - **How were the following treated: transmission service; FTRs; participation by affiliates, including the use of utility land/facilities?**
  - **Discuss creditworthiness screening, conduct of the bid/auction, post-bid negotiations, regulatory oversight, and independent observer.**

3. **Prior to initiating a competitive solicitation, should there be a collaborative process (outreach) to achieve consensus on issues with respect to the solicitation design and the evaluation criteria to be used? If so, what should be the characteristics of that collaborative process?**
4. **Are there ways to ensure that there is no preferential dealing among affiliates in soliciting and awarding power purchase agreements? If so, what safeguards should be included?**
5. **To what extent are transmission service and monopsony power factors in the competitive solicitation? What criteria should be established under the Commission's Edgar policy to ensure that all participants are treated in a non-discriminatory manner?**
6. **Should a market monitor or independent entity oversee the administration of solicitations in which affiliates are involved? To the extent a monitor is involved, what criteria should be established to ensure that the monitor is independent of all parties participating in the solicitation process? For example, how should the monitor be selected? By whom? To whom should the monitor report? Who should pay for the monitor's services?**
7. **Provide proposals for "best practice" competitive solicitation methods or principles that could be used to ensure that power transactions are the result of a fair, transparent and accurate process.**
8. **How can FERC and state regulators coordinate in the design and oversight of solicitation processes?**

***Status:***

- Technical conference held June 10<sup>th</sup>
- Post Technical Conference Comments filed on July 1.
- No Final Order yet issued in these proceedings.

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***Recent Cases Pertaining:***

ER04-730, Allegheny Energy Supply (Section 205)

***Market Power Issues:***

- On 4/13/04 AE Supply filed an application, pursuant to Section 205, stating that as part of an RFP process supervised by the Maryland

Commission, AE Supply had been selected to supply the Potomac Edison Co. with full requirements service to fulfill some of Potomac's standard offer service obligation.

- AE sought Commission approval of affiliate PPA at market-based rates.

***Status:***

- Commission approved PPA on 7/29/04, 108 FERC ¶ 61,082 (2004).
- FERC concluded that Maryland Commission competitive bidding process satisfied the Commission's concerns over the potential for affiliate abuse
- Commission also provided guidance as to the standards FERC will use in the future to determine whether an affiliate filing meets the Edgar standard. The following guidelines will be used by the Commission: (1) Transparency—the competitive solicitation process should be open and fair, (2) Definition—the products sought through the competitive solicitation should be precisely defined, (3) Evaluation—evaluation criteria should be standardized and applied equally to all bids and bidders, (4) Oversight—an independent third party should design the solicitation, administer bidding and evaluate the bids prior to the company's selection. 108 FERC ¶ 61,082, 61,417 (2004).

ER04-316, SCE/Mountainview (Section 205)

***Market Power Issues:***

- Southern California Edison Co. requested an expedited Section 205 approval of a cost-based purchase power agreement with Mountainview Power LLC, an affiliated exempt wholesale generator. SoCal had signed an option agreement to purchase Mountainview, an uncompleted generating unit owned by Sequoia, a subsidiary of InterGen, Inc.
- California Public Utilities Commission approved the PPA, holding that the proposed transaction would benefit consumers and that SoCal had established an immediate need for dispatchable peaking and intermediate capacity.
- Opponents argued that SCE did not use a competitive bidding process for required capacity and that the absence of competitive procurement will negatively impact wholesale power market in region.

***Status:***

- Commission approved PPA on 2/25/04 as being consistent with Commission policy. 109 FERC ¶ 61,086 (2004).

- Commission announced policy that it will henceforth require that all affiliate PPAs, whether at cost or market-based, be subject to the conditions set forth in Edgar. Concerned that cost-based rates may exceed market—potential for affiliate abuse.
- Order on Rehearing issued on 10/28/04. That Order (1) Rejected rehearing on all major issues, (2) Rejected request of Competitive Supplier group for the commission to clarify exact conditions that would have to be met to pass new Edgar test, (3) Rejected request of Competitive Suppliers for the Commission to adopt the EPSA competitive solicitation guidelines.

ER03-583, Entergy Services (Section 205)

***Market Power Issues:***

- Proposed purchase power agreements with affiliate
- 8 proposed PPAs at market-based rates filed under Section 205
- Interveners argue RFP process inconsistent with *Edgar* and will negatively impact wholesale competition.

***Status:***

- Commission order suspending PPAs issued on 5/30/03. 103 FERC ¶ 61,256 (2003). Hearing to focus on fairness of RFP process and impact on competition completed. Briefing process currently ongoing. Initial decision scheduled for 7/1/05.

ER03-713, Southern Power Co. (Section 205)

***Market Power Issues:***

- Proposed Section 205 purchase power agreement between Southern Power and two affiliates
- 2 market-based long term PPAs
- Hearing will focus on consistency of RFP process with Edgar standard.
- Interveners allege Southern used transmission service reservation process to advantage affiliates
- Issue of whether the awarding of the PPA contracts to an affiliate will negatively impact wholesale competition.

***Status:***

- Commission order suspending PPAs issued on 7/9/03. 104 FERC ¶ 61,041 (2003). Hearing to focus on fairness of RFP process and impact on competition
- Staff testimony on 12/19/03 recommends that the Commission not approve PPAs because: (1) Concerns that cross subsidization, preferential information sharing and vertical foreclosure may negatively impact wholesale competition, and (2) RFP process and bid evaluation was clearly biased in favor of affiliates.
- On 5/7 Georgia Power and Savannah Electric filed a request with Georgia Commission for direction to purchase McIntosh Units 10 and 11.
- Georgia Commission approved sale on 5/18. Commission ruled companies will be able to recover the lesser of book or fair market value
- Southern filed a motion on 5/20 to (a) cancel the rates that had been previously accepted for filing, (b) withdraw MBR application, and (c) terminate proceeding.
- FERC Issued a notice accepting the withdrawals on 8/4/04. 108 FERC ¶ 61,134 (2004).

## **Transfers of Utility Assets to Utility from Affiliate**

**Ameren Energy Generating Company, Union Electric Company, d/b/a AmerenUE,  
108 F.E.R.C. para. 61,081**

### **I. Background on Section 203**

Section 203(a) of the Federal Power Act provides:

No public utility shall sell, lease, or otherwise dispose of the whole of its facilities subject to the jurisdiction of the Commission, or any part thereof of a value in excess of \$ 50,000, or by any means whatsoever, directly or indirectly, merge or consolidate such facilities or any part thereof with those of any other person, or purchase, acquire, or take any security of any other public utility, without first having secured an order of the commission authorizing it to do so. Upon application for such approval the Commission shall give reasonable notice in writing to the Governor and State commission of each of the States in which the physical property affected, or any part thereof, is situated, and to such other persons as it may deem advisable. After notice and opportunity for hearing, if the Commission finds that the proposed disposition, consolidation, acquisition, or control will be consistent with the public interest, it shall approve the same.

- A. "Facilities subject to the jurisdiction of the Commission" includes transmission (and certain other facilities), but not generation facilities.
- B. FERC applies Section 203 to mergers, where the control of jurisdictional facilities moves from a "public utility" to another entity.
- C. Where the only "jurisdictional facility" being transferred is a transmission asset, but there is generation transferred also, FERC will look at the effect on the public interest of the transfer of all assets (i.e., jurisdictional transmission as well as non-jurisdictional generation). FERC thus will look at the effect on the public interest of a disposition of generation assets, even though generation assets are not "facilities subject to the jurisdiction of the Commission," if the transaction also involves the transfer of transmission assets.

### **II. Affiliate Abuse Precedent from the Interaffiliate Market Pricing Cases**

- A. *Edgar* required one of three showings for approval of a utility's purchase from its generation affiliate:

1. evidence of direct head-to-head competition between the affiliate and competing unaffiliated suppliers in a formal solicitation or informal negotiation process;
  2. evidence of the prices which non-affiliated buyers were willing to pay for similar services from the affiliate; and
  3. benchmark evidence that shows the prices, terms and conditions of sales made by non-affiliated sellers.
- B. *See Boston Edison Company Re: Edgar Electric Co.*, 55 FERC P 61,382 (1991). The Commission has explained that "these examples were not an all-inclusive list; the individual facts of a case could bring forth other examples not expressed in *Edgar* to show that a transaction is without affiliate abuse." *Ameren* at n.14.

### **III. *Ameren*: Application of *Edgar* to Asset Transfers From Affiliates to Utilities**

- A. *Edgar* requirements will apply not only to sales of power from affiliate to utility, but also to transfer of assets from affiliate to utility.
- B. Concern is not concentration of generation ownership. (para. 64)
- C. Concern: raising entry barriers by increasing the costs of unsuccessful entry (Para. 63)
1. affiliate safety net
  2. monopsony power (para. 63)
- D. Solicitation by the utility is not mandatory,
- E. Solicitation Guidelines [paras. 69-70]: The fundamental objective of the solicitation guidelines is that the affiliate should have no undue advantage over non-affiliates in the solicitation process. So, four separate requirements:
1. Transparency: the competitive solicitation process should be open and fair.
  2. Definition: the product or products sought through the competitive solicitation should be precisely defined.

3. Evaluation: evaluation criteria should be standardized and applied equally to all bids and bidders.
4. Oversight: an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection.

#### **IV. Commissioner Kelliher Concerns**

- A. The scope of Section 203 differs from Section 205

"In my view, the Commission's interest in proceedings under section 203 is fundamentally different from its interest under section 205. In a power purchase agreement involving an affiliate, the Commission has a legitimate interest in assuring that the process was fair, because we have a legal duty to assure just and reasonable rates and prevent undue discrimination or preference. In a section 203 proceeding, our interest is different because the legal standard is different. The Commission does not have a legal duty to assure that acquisitions of facilities are just and reasonable, or to prevent undue discrimination or preference in such dispositions. The public interest standard governs. While the Commission has discretion to determine just what that means, our interpretation must be guided by the fact that our legal duty to prevent undue discrimination and preference is limited to wholesale power sales and the transmission of electric energy in interstate commerce. n72 The disposition of a facility is neither. The Commission does not have a general charge to prevent any undue discrimination or preference in the electricity industry, but only in these two discrete areas." n.73

n.73 See generally NAACP v. Federal Power Commission, 425 U.S. 662, 664 (1976) (holding that the legislative intent of neither the Federal Power Act nor the Natural Gas Act included a "public interest" in eliminating employment discrimination).

- B. The risk to retail ratepayers of abusive self-dealing is a concern of state commissions, not of FERC

"This competitive solicitation policy is designed to prevent an unfair solicitation in the acquisition of an affiliated facility by a public utility. I can appreciate that a competitive solicitation process can guard against a public utility overpaying or underpaying in such an acquisition. The Commission has a legal

duty to prevent abusive self-dealing and cross-subsidies in jurisdictional services. However, it is the responsibility of a state commission, not this Commission, to ensure that a state-regulated utility does not subsidize an affiliate in the purchase of an asset. Like the presiding judge, I am not prepared to assume regulatory failure on the part of[\*69] state commissions. n74"

"n74 The competitive solicitation policy may also be designed to ensure that nonaffiliated generators have access to cash infusions from asset sales. If so, this seems to go beyond the pale. The Commission has a legal duty to promote competition, not competitors."

C. The Commission's focus should be on the effects on competition.

"The Commission's interest in a jurisdictional disposition is on consideration of (1) the effect on competition, (2) the effect on rates, and (3) the effect on regulation. n75 The Commission previously found the proposed disposition in this order would have no adverse effect on rates and regulation, n76 and I see no reason to disturb those findings. The narrow question before the Commission in this order is whether the proposed transaction would have an effect on competition. In my view, the principal inquiry should be the impact of a proposed disposition on a public utility's market power. By this measure, the proposed disposition would not have a negative effect on competition."

*Excerpts from*

**Ameren Energy Generating Company, Union Electric Company, d/b/a AmerenUE  
Docket Nos. EC03-53-000, EC03-53-001, OPINION NO. 473**

**108 F.E.R.C. P61,081; 2004 FERC LEXIS 1571**

**ORDER AFFIRMING INITIAL DECISION IN PART, DENYING REQUESTS FOR  
REHEARING AND ANNOUNCING NEW GUIDELINES FOR EVALUATING  
SECTION 203 AFFILIATE TRANSACTIONS**

**July 29, 2004**

1. In a Hearing Order, n1 *the Commission set for hearing the effect on competition of a proposed disposition from Ameren Energy Generating Company (AEG) to its corporate affiliate Union Electric Company d/b/a AmerenUE (AmerenUE) (collectively, Applicants) of jurisdictional facilities associated with the sale of certain generating assets.* The Presiding Administrative Law Judge (judge) issued an Initial Decision n2 finding that the proposed transaction will[\*2] not have an adverse effect on competition. As discussed below, we affirm the Initial Decision in part, with discussion of certain findings. Since we already found in the Hearing Order that the proposed disposition has no adverse effect on rates and regulation, n3 we will authorize the proposed disposition of facilities as consistent with the public interest.

2. In addition, as discussed below, we announce our expectations for *future section 203 transactions involving disposition of jurisdictional facilities between affiliates* (hereinafter called affiliate transactions). The Commission has concluded that there should be more definition as to[\*3] what showing is adequate to demonstrate that a proposed affiliate transaction *will not harm competition or otherwise be inconsistent with the public interest*. The objective of this policy is to ensure that the *conduct of competitive solicitations involving affiliates does not harm competitive markets by favoring those affiliates and foreclosing opportunities to competition*. This policy will allow us to quickly identify affiliate transactions that are unlikely to involve affiliate abuse and can be approved without a trial-type hearing. This expectation will be *applied prospectively* to avoid regulatory effect on transactions already filed for Commission approval, i.e., filed as of the date of issuance of this order.

4. *AmerenUE, a subsidiary of the Ameren Corporation (Ameren), provides wholesale and retail electric service and retail gas service to customers in*

**Missouri and Illinois. n4 AmerenUE owns about 8,500 megawatts (MW) of generating capacity and also purchases[\*4] power to meet its peak load, which exceeded 8,600 MW in 2002.** Central Illinois Public Service Company d/b/a AmerenCIPS (AmerenCIPS), also a subsidiary of Ameren, provides retail electric and gas service to customers in Illinois. Both AmerenUE and AmerenCIPS provide transmission service under the Ameren Open Access Transmission Tariff, and Ameren has joined the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) through GridAmerica, an independent transmission company.

5. **AEG owns generating resources of approximately 4,600 MW** and sells wholesale power to its affiliate, Ameren Energy Marketing Company (AEM), and to non-affiliates. n5 AEG owns the Pinckneyville, Illinois generation facility (Pinckneyville), consisting of eight combustion turbine generator units with [\*5]a total capacity of 316 MW, and the Kinmundy, Illinois generation facility (Kinmundy), consisting of two combustion turbine generator units with a total capacity of 232 MW.

n5 **AEG does not own a transmission system and does not provide retail service.** Most of AEG's resources were transferred to it from AmerenCIPS in 1999. AEM's purchases from AEG are principally resold to AmerenCIPS and used to serve AmerenCIPS' retail customers.

6. On February 5, 2003, AEG and AmerenUE filed an application under section 203 of the Federal Power Act (FPA) n6 requesting Commission authorization for the transfer of certain jurisdictional transmission facilities associated with the sale of the Pinckneyville and the Kinmundy facilities from AEG to AmerenUE (proposed transaction). **Upon consummation of the transaction, AmerenUE would own an additional 548 MW of generation capacity.**

7. **According to Applicants, the purpose of the transaction is to enable AmerenUE to meet its peak load requirements,** both short-term and long-term, including planning reserve requirements (15 percent for 2003 and 17 percent for 2006) of the Mid-America Interconnected Network, Inc. (MAIN) regional reliability council. Applicants state that to meet its peak load requirements AmerenUE needs an additional 543 MW in 2003, increasing to 991 MW in 2006.

8. Applicants argued that AmerenUE's decision to meet its needs by buying the Pinckneyville and Kinmundy plants was a reasonable one that does not reflect affiliate preference. Applicants stated that the **choice of these plants was based on AmerenUE's resource planning process** and was consistent with a Stipulation and Agreement (Missouri Stipulation) among AmerenUE, the Missouri Public Service Commission (Missouri Commission) Staff and other entities that was **approved by the Missouri Commission.** n7 Applicants also asserted that **the proposed price of the facilities was reasonable, in comparison with other recent**

*sales of similar types of generating capacity used for peaking purposes.*

According to Applicants, AmerenUE analyzed several [\*7] options in addition to the proposed purchase, *such as purchasing power on the market, purchasing existing assets from non-affiliates, and building new capacity*, before reaching a decision.

n7 The Missouri Stipulation requires AmerenUE to acquire 700 MW of new "regulated" generating capacity by June 30, 2006, and specifically states that this requirement may be met by the *purchase of generation plant from an Ameren affiliate at net book value*. The Missouri Stipulation also requires that AmerenUE construct *new transmission lines and transmission upgrades that will increase transmission import capability by 1,300 MW. In addition, the Missouri Stipulation provides that retail rates will remain frozen*, except for certain specified rate decreases, through June 30, 2006.

10. In 1996, the Commission issued the Merger Policy Statement setting forth procedures, criteria and policies applicable to public utility mergers and other dispositions of jurisdictional facilities. n9 The *Merger Policy Statement* and Order No. 642, n10 which sets forth the Commission's filing requirements for section 203 applications, provide that the Commission will generally take account of *three factors in its section 203 analysis: (a) the effect on competition; (b) the effect on rates; and (c) the effect on regulation.*

11. In the Hearing Order, the Commission found that while the proposed transaction would have *no adverse effect on rates and regulation*, Applicants had not shown that the proposed transaction would not adversely affect competition. The Commission noted that the proposed transaction was the *second time within a very short period that our approval had been sought for this type of affiliate transaction*. In the prior case, Cinergy Services, Inc., et al., we approved the transaction but expressed our concern over the possible implications of these types of affiliate transactions. n11 We noted that *"the ability of a franchised utility to assume its affiliated merchant's generation when market demand declines gives the affiliated merchant a 'safety net' that merchant[\*10] generators not affiliated with a franchised utility lack."* n12 We expressed concern that *"the existence of a safety net may affect the incentive of new merchant generators to invest in new facilities," erecting a barrier to entry that harms the competitive process and raises prices to customers in the long run "because affiliated merchant generation with a safety net option will not be subject to the price discipline of a competitive market."* n13 We further indicated, in Cinergy, that in light of our concerns, we would modify our future approach to analyzing the competitive effects of intra-corporate transactions of this nature.

12. In the Hearing Order, we stated that Applicants' proposed transaction presented the types of competitive concerns we expressed in Cinergy. We further stated that *we had no established standards to evaluate section 203 affiliate transactions to[\*11] ensure that affiliate abuse has not occurred*. In contrast, we noted, *we do have such standards, developed in Boston Edison Company Re: Edgar Electric Co., n14 for evaluating the justness and reasonableness of a franchised utility's wholesale transactions (contracts) involving an affiliate to ensure that affiliate abuse has not occurred and to ensure prices that are consistent with competitive outcomes*. That case presents several examples of how a utility can demonstrate that there was no affiliate abuse. We stated that the two situations are similar and that *a franchised utility should be required to demonstrate that its purchase of an affiliate's plant* is on terms similar to any other competitive alternatives available. Finally, we expressed our concerns regarding the adequacy of the evidence offered by Applicants and, therefore, we set the proposed transaction for hearing to examine its possible effects on competition.

n14 55 FERC P 61,382 (1991) (Edgar). *In Edgar, the Commission gave three examples of how to demonstrate lack of affiliate abuse: (1) evidence of direct head-to-head competition between affiliated and unaffiliated suppliers; (2) evidence of the prices that non-affiliated buyers were willing to pay for similar services from the affiliate; and (3) "benchmark" evidence of the prices, terms and conditions of sales made by non-affiliated sellers. These examples were not an all-inclusive list; the individual facts of a case could bring forth other examples not expressed in Edgar to show that a transaction is without affiliate abuse.*

15. *The judge concluded that AmerenUE had established that the proposed transaction would not have an adverse impact on competition. The judge found that because AmerenUE and AEG are affiliates, the proposed transaction will result in no change in market concentration. In addition, the judge stated that since the Commission has granted both AmerenUE and AEG market-based rate authority, the Commission believed that Ameren's wholesale markets were workably competitive. The judge further determined that AmerenUE's customers are adequately protected because AmerenUE was subject to a retail rate freeze through June 2006, and any subsequent retail rate filing would be subject to state review, thus hindering AmerenUE's ability to recover an acquisition premium from its ratepayers.*

16. *The judge also found that the Commission's safety net theory was not valid, and even if the theory is valid, the proposed transaction does not raise safety net concerns. The judge agreed with AmerenUE's and Trial Staff's witnesses, and found that before[\*14] the safety net concern can be viewed as a valid competitive theory, there must be, among other things, evidence of a sale above*

*market value.* The judge found that there was no evidence here that the acquisition prices of the Pinckneyville and Kinmundy facilities at net book value were above market prices and concluded that the *acquisition prices resulted from a competitive process.* The judge further concluded that it had not been shown that the proposed transaction would have a significant effect on the cost of capital. Moreover, the judge gave substantial weight to testimony that the *safety net theory ultimately fails because it assumes widespread, systematic regulatory failure. In fact, the judge noted, the relevant state regulator - the Missouri Commission - has demonstrated that it is capable and willing to protect its retail customers.*

18. In addition, the judge concluded that *no evidence of affiliate abuse was present in AmerenUE's Request for Proposal (RFP) process. The judge found that AmerenUE used an adequate RFP process, which considered various non-affiliated suppliers but properly eliminated them as contenders for a variety of price and non-price reasons.* She determined that the evidence demonstrated that there were no improvements to AmerenUE's transmission infrastructure since the RFP was issued in August 2001 that would make more viable those options that had been excluded due to transmission concerns. Furthermore, the judge found that there had been no material change in market fundamentals since the issuance of the RFP that would produce any significant difference in price. She concluded, therefore, that a more current RFP in this case would not be useful because it was unlikely to bring forth any viable new options.

24. *Applicants[\*19] argue that the Commission lacks jurisdiction over the generating assets at issue and therefore that any inquiry into the competitive effect of the transfer of these units is beyond the Commission's jurisdiction. They note that the Commission only has jurisdiction over a minor portion of the transaction -- the transfer of the facilities used to interconnect the Kinmundy and Pinckneyville units to the bulk transmission grid. n18 Applicants reason that since the Commission does not have jurisdiction over the transfer of generation assets, the Commission cannot use its jurisdiction over these minor transmission facilities to regulate indirectly what it cannot regulate directly; the Commission erred by using its jurisdiction over this minor portion of the transaction to consider the effects of the remainder of the transaction. Moreover, Applicants argue that the Commission did not identify, nor did anyone claim, that the proposed transfer of these interconnection facilities would have any adverse effect on competition. Furthermore, Applicants state that these interconnection facilities do not perform a transmission function.*

-----Footnotes-----

n18 *Applicants estimate that the total value of the interconnection facilities is approximately five percent of the total value of the transaction.*

25. *We need not decide this point, since we find in any event that the proposed transaction is consistent with the public interest. As such, we approve the transaction. Furthermore, we note that even Applicants concede that the disposition of the interconnection facilities associated with the proposed transaction requires Commission authorization pursuant to section 203. When reviewing applications made under that section, the Commission evaluates the entire transaction to determine whether the proposed disposition of jurisdictional facilities is consistent with the public interest. If a portion of a transaction requires authorization under section 203, the overall effect of the transaction must be considered before approval may be granted.* n19 We cannot ignore the full implications of a transaction for the public interest; the disposition of the transmission facilities is an integral part of the overall transaction.

n19 See *Iowa Southern Utilities Company*, 35 FERC P 61,149 at 61,360, n.1 (1986) [*The Commission determined that if a portion of a transaction requires authorization under section 203, the entire transaction is to be considered in determining whether the public interest is satisfied before approval may be granted.*] See also *Trans-Elect, Inc. et al.*, 98 FERC P 61,368 at 62,594 (2002); *Niagara Mohawk Power Corp., et al.*, 89 FERC P 61,124 at 61,347 (1999); *Duquesne Light Co.*, 88 FERC P 61, 248 at 61,793 (1999).

26. Applicants note that the proposed transaction is supported by the Missouri Commission, the only state commission affected by the transfer. n20 *Moreover, they contend that when they entered into the Missouri Stipulation they relied on the Commission's pre-Cinergy precedent regarding intra-corporate transfers of generation, in which the Commission held that intra-corporate transactions generally do not present any concerns about harm to competition.* Applicants argue that failure to approve the proposed transfer will undermine the Missouri Stipulation and the Missouri Commission's preference for AmerenUE to acquire dedicated assets to meet its load requirements.

29. Applicants argue that the Commission's focus on the competitive effect of this particular transaction is misplaced because this transaction is *not a typical sale of merchant generation by an independent power producer to an affiliated IOU. They argue that AEG is not a true merchant generator, since the AEG units are designated resources (under a Commission-approved Joint Dispatch Agreement (JDA)) [\*24] that are committed exclusively to serve load requirements before any output can be sold on the market. As a result, Applicants contend, AEG is closer to being a franchised utility than a true merchant generator.* Applicants allege that after the transfer to AmerenUE, the generating units will continue to operate in the same manner and will continue to serve the same overall Ameren

load (via the JDA). Thus, they argue, there can be no effect on competition and the safety net concerns are not valid here.

36. Endorsing the reasoning of Trial Staff's witness Boner and Applicants' witnesses Frame and Asselstine, the judge dismissed the "safety net" hypothesis as theoretically unsound, lacking empirical basis, and unsubstantiated by the facts of this case. n23 She found that the proposed[\*27] transaction resulted from a competitive process and that acquisition prices in this case were not proved to be above market value. ***Citing to witness Asselstine's testimony, the judge also found no evidence that potential non-affiliated generators generally face higher costs of capital in obtaining investment capital because lenders or investors perceive a safety net advantage for affiliated generator competitors. She further found no evidence that in this case, the developers of AEG's plants paid less for capital because of a perceived "safety net."*** n24

37. In addition, the judge agreed with Trial Staff's witness Boner and Applicants' witness Frame that in order for the safety net predictions to come true, there must be regulatory failure; i.e., the theory assumes that state and federal regulators will not prevent affiliate abuse and will allow recovery of above-market prices in their prudence reviews of the transaction [\*28] when the acquiring entity attempts to include in its rate base the cost of the acquisition. n25 ***She also found persuasive witness Boner's point that even if the investment community perceives that there is a safety net for affiliated generators because of ineffective regulation in one state, possibly resulting in higher capital costs for potential non-affiliated generators that may locate in markets affected in that state, this would not be a barrier to entry into other markets. The judge placed great weight on the Missouri Commission's support for the transaction and its assurance that a state prudence review will be conducted in the future.*** n26

38. On exceptions, ***NRG claims that the Hearing Order did not set the validity of the "safety net" concerns for hearing. It also contends that the judge ignored the very important point made by witness Roach that the safety net concern does not assume regulatory failure, because even if regulation works perfectly, any remedy[\*29] at the prudence review stage would be too late to protect the wholesale market from the adverse effects of intra-corporate transactions.*** n27

46. We agree with the judge that the validity of the safety net theory both generally and specifically in this case were proper issues to consider. ***We affirm the judge's finding that affiliate abuse did not occur; AmerenUE appropriately decided among alternatives on the basis of price and non-price factors. Therefore, AmerenUE's acquisition of the Pinckneyville and Kimmunity facilities will not represent an exercise of a safety net for Ameren and its subsidiaries.***

47. *However, we reverse the judge's findings that safety net is not a generally valid concern and that for a safety net transaction to harm competition, there must be regulatory failure and such regulatory failure must be widespread and systematic. In addition, the judge gave undue credence to the proposition that a utility that sells power in a competitive market, and thus is not guaranteed recovery of its costs, has no incentive to pay more than market value for a generating asset being used for sales for resale in interstate commerce, i.e., to engage in a safety net transaction that benefits its affiliate. As we explain below, the Commission continues to believe that affiliate [\*37] acquisitions by their very nature raise concerns about the potential for discriminatory treatment in favor of the affiliate's plant, which can undermine competition and harm the public interest.*

48. *The Commission recognizes that effective regulatory review at the federal and state levels can prevent excessive rates to wholesale and retail customers respectively of the acquiring utility. However, our obligation under section 203 is to decide at the time a transaction is filed, and before it is consummated, whether the transaction will adversely affect competition and is consistent with the public interest. While effective state regulatory review can prevent excessive rates to the retail customers of the acquiring utility, it is not a remedy for the anticompetitive effects of affiliate preference, which harm all customers. The possibility of eventual regulatory review does not prevent the exercise of affiliate preference before the transaction occurs. We are also not convinced that such eventual regulatory review of rates is an effective remedy for anticompetitive effects that arise at the time affiliate preference occurs. Ultimately, all customers are harmed because competition[\*38] is undermined.*

53. *As discussed below, however, we believe that the competitive implications of intra-corporate asset transfers are similar to those of intra-corporate sales contracts; therefore, we will apply the standards developed in Edgar to future section 203 applications involving affiliated [\*42] generation. n40 Moreover, as noted by the Federal Trade Commission (FTC):*

*FERC already has a policy in place (the Edgar policy) that is intended to promote objective make-or-buy decisions by utilities regarding contracts for power. Because the issues involved in affiliate asset transfers are similar to the issues involved in power supply contracts with affiliates are similar to those entailed by affiliate asset transfers, FERC may wish to consider a similar framework for reviewing affiliate asset transfers. n41*

n40 *As we have stated in a series of cases, we believe that affiliate preference, or the possibility thereof, whether in market-based or cost-based*

*PPAs or in asset acquisitions, harms competition. See, e.g., Southern California Edison Company on behalf of Mountainview Power Company, LLC ( Mountainview) 106 FERC P 61,183 (2004), reh'g pending: "We are also concerned that granting undue preference to affiliates, whether through cost-based or market-based transactions, could cause long-term harm to the wholesale competitive market. Affiliate preference could discourage non-affiliates from adding supply in the local area, harming wholesale competition and, ultimately, wholesale customers."*

*54. Applicants submitted testimony by Metcalfe n42 and Voytas n43 on benchmark evidence of comparable transactions in an attempt to meet the third Edgar example. Using coal and gas-fired plants over the years 2001 to 2003, both concluded that the net book value of the proposed transaction was within the range of benchmark prices. To enhance comparability, Trial Staff witness Fager modified their analyses to exclude plants outside the Eastern Interconnect, plants that are not gas-fired, and affiliate transactions. n44 As a result, the average price of the benchmark transactions in the revised analysis was \$450/kW, compared to the average price of \$467/kW of the Pinckneyville and Kinmundy transfers. Although she concluded that the remaining transactions in the revised analysis still lacked sufficient comparability[\*44] to firmly support the price of the AEG plants, the judge noted that they were in line with the acquisition cost. n45 The judge found that both Metcalfe and Fager followed the standards of Ocean State, n46 and gave both their studies substantial weight. n47*

*57. EPSA is correct that these benchmark analyses provide little insight. The seven plants in Trial Staff Witness Fager's revised analysis use different technologies. n53 There is no trend or real sense of market conditions. Indeed, Fager gives only qualified support to the benchmark evidence, noting that she could " not verify the price is correct, although it has not been shown to be incorrect." n54*

*59. In future section 203 applications that involve the acquisition of an affiliate's assets, we will review the transaction's effect on competition based on the standards developed in Edgar. n57 Acquisitions involving affiliates have an inherent potential[\*48] for discriminatory treatment in favor of the affiliate. Affiliate preference when acquiring assets can have serious adverse effects on competition and may therefore not be consistent with the public interest. In determining that such acquisitions are consistent with the public interest, as section 203 requires, the Commission must assure that a public utility's acquisition of a plant from an affiliate is free from preferential treatment. The public interest requires policies that do not harm the development of vibrant, fully competitive generation markets.*

60. *Preferential procurement of an affiliate asset by a public utility may harm competition in electricity markets in a number of ways. These include raising entry barriers, increasing market power and impeding market efficiency.* Such harm can adversely affect existing market conditions or impede innovation and efficiency in the long run. As noted by the FTC, "utilities may have both incentives and the ability to exercise market power and [\*49] harm consumers by discriminating in favor of their own affiliates and against independent suppliers."  
n58

61. *Potential non-affiliated generators that perceive that affiliated generators have a "safety net" available to them may be discouraged from entering the market. While after-the-fact prudence reviews by regulators may insulate ratepayers from the effects of a purchase price that is too high, they will not remedy the foreclosure of additional competitors from the market. The Commission must decide at the time of a section 203 application whether an acquisition will adversely affect competition or the public interest. Our responsibility under section 203 is to protect the public interest, and Congress intended us to take action before the disposition of facilities is consummated.*  
n59

*n59 An analogous situation occurs in our consideration of another factor in our section 203 analysis, the effect of a disposition of facilities on rates. We do not postpone an analysis of the effect on rates until an acquiring utility makes a rate filing under section 205; under section 203, we also analyze the likely effect on rates of a disposition of facilities before we approve it.*

62. *Affiliate preference in procurement may harm competition and thereby efficiency. If non-affiliated generators (i.e., wholesale competitors) leave or do not enter the market due to preferential procurement competition in wholesale markets will be harmed, and market concentration and market power may even increase. Further, if the utility's affiliate preference causes less efficient generation to be used and more efficient capacity to exit or not enter the market, the costs of providing power are unnecessarily higher. One such example would be when a more efficient generator exits the market because a key buyer, the franchised local utility, acquires a less efficient generating facility from an affiliate. In a competitive market, the less efficient generator would exit, resulting in more efficient dispatch and lower prices.* n60

*n60 See, FTC Comments at 10: "One potential adverse impact is that discrimination in affiliate transactions (procurement of generation assets or power supply contracts from affiliates at inflated prices, or below-market sales to affiliates) may result in the exit of more efficient generation assets and the retention of less efficient generation assets in the event, for example, that demand declines enough to force some exit from the market. In a market where capacity exceeds demand, some assets may exit from the market. Absent discrimination, the*

*least efficient assets are the most likely assets to exit. In the presence of discrimination, less efficient assets owned by the utility or its affiliates are more likely to remain in the market while more efficient independent suppliers are forced to exit."*

*63. Preferential procurement also raises entry barriers by increasing the cost of unsuccessful entry. One of the factors a potential entrant would rationally consider before entering a market is the extent to which it is likely to recover its investment in fixed assets. A franchised public utility is generally a major purchaser of generation resources in a region and thus may have some degree of buyer market power, or monopsony power. Purchase of an asset through a utility procurement to serve the utility's franchised load may be the best opportunity in some regions for a power plant investment to succeed or, in the event of failure, to recover its investment. In a less concentrated buyer's market (less monopsony power), a firm seeking to exit a particular market would sell its assets to other market participants for a fair market value. However, if a franchised utility has buyer market power, the price that the exiting firm will recover is likely to be less. This increased proportion of total costs likely to be unrecoverable by an exiting firm is a barrier to entry. n61*

*n61 See, e.g., DENNIS W. CARLTON AND JEFFREY M. PERLOFF, MODERN INDUSTRIAL ORGANIZATION (Addison Wesley 2nd ed. 1994) at 111: "An important consideration in understanding a firm's incentive to enter an industry is, paradoxically, the firm's ability to exit the industry. If it is costly to exit an industry, the incentives to enter are reduced." See also FTC Comments at 11: "Absent discrimination, any specific generation entrant can reasonably expect to sell its generation assets at the fair market price in the event that its entry fails. In the presence of discrimination by utilities, the selling price for liquidated stand-alone generation assets is likely to be lower where the distribution utility in the area is one of the most likely purchasers of such assets, absent discrimination, or where there are few potential buyers. The result of this increased risk is that entry becomes less likely." (footnote omitted)."*

*64. The Commission has not required a competitive analysis screen for intra-corporate transfers. The Commission found in the past that "anticompetitive effects are unlikely to arise with regard to internal corporate reorganizations or transactions." n62 However, that statement referred to anticompetitive effects of a consolidation of generation - an increase in the market share of the acquiring firm, market concentration (e.g. the Herfindahl-Hirschman Index (HHI)), and potentially, an increase in market power. Today, to fulfill our responsibility under the FPA to analyze effects on the public interest generally, and on the competitiveness of markets in particular, we have come to the conclusion that a section 203 affiliate transaction is not consistent with the public interest unless shown not to be result of affiliate abuse. We conclude that, absent other compelling public interest considerations, we can no longer*

*find a section 203 affiliate transaction to be consistent with the public interest unless the applicants demonstrate that appropriate steps were taken to safeguard against affiliate abuse, consistent with the Edgar standard.*

*66. In El Paso, we announced a transmission comparability standard for evaluating whether a transaction is consistent with the public interest. Our concern was, in part, that not offering comparable transmission service would be unduly discriminatory. [\*54] We continue to believe that undue discrimination is an appropriate public interest consideration in evaluating transactions under section 203. Affiliate abuse is a form of undue discrimination. We have expressed our concern about affiliate abuse in a variety of contexts n65 and have become increasingly concerned about the effect of affiliate abuse in cases involving the disposition of facilities in today's market conditions. To address these concerns, and to ensure that asset purchases from affiliates as well as purchase power contracts with affiliates are both reviewed for affiliate preference, we believe it is appropriate to evaluate section 203 transactions based on the Edgar standards used under section 205.*

*67. We note that there are three ways to demonstrate lack of affiliate abuse under the Edgar standard: (1) evidence of direct head-to-head competition between the affiliate and competing unaffiliated suppliers in a formal solicitation or informal negotiation process; (2) evidence of the prices which non-affiliated buyers were willing to pay for similar services from the affiliate; and (3) benchmark evidence that shows the prices, terms and conditions of sales made by non-affiliated sellers. Because the market for generating assets is not nearly as liquid as the market for PPAs, a competitive solicitation through a formal RFP in future section 203 cases is likely to be the most effective way to show that an affiliate transaction is not marred by affiliate abuse. In the context of an acquisition of affiliated generation, a competitive solicitation is the most direct and reliable way to ensure no affiliate preference.*

*68. We will not make competitive solicitations mandatory in this order. However, to the extent a utility demonstrates that its RFP process follows the guidelines discussed below, it should greatly reduce application processing time (including litigation) [\*56] and increase the likelihood of timely Commission approval because an adequate showing of meeting the Edgar standard has been made. In other words, the guidelines described below will allow us to more easily identify transactions that are consistent with the public interest, and, therefore, expedite their approval. n67*

*69. The fundamental objective of the solicitation guidelines is that the affiliate should have no undue advantage over non-affiliates in the solicitation process. Adhering to the guidelines will ensure that wholesale customers receive the benefit of the marketplace, including an unbiased assessment of the full range*

*of choices, whether the soliciting utility provides service[\*57] at cost-or market-based rates.*

*70. The solicitation guidelines have four principles:*

*a. Transparency: the competitive solicitation process should be open and fair.*

*b. Definition: the product or products sought through the competitive solicitation should be precisely defined.*

*c. Evaluation: evaluation criteria should be standardized and applied equally to all bids and bidders.*

*d. Oversight: an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection. n68*

*n68 We note that in a section 205 proceeding involving an affiliate power sales contract that is being issued concurrently, an independent consultant was selected by the state commission, and its compensation determined by the state commission, to monitor the RFP process. The independent consultant reported its findings to the state commission, which also supervised other aspects of the RFP process. See Allegheny Energy Supply Company, LLC, 108 FERC P 61,082 (2004).*

*71. These principles apply to different stages and aspects of the solicitation process. The transparency and oversight principles apply to all aspects of the competitive solicitation, the definition principle applies in the design of the RFP, the evaluation principle applies as bids are evaluated, and the oversight principle, like the transparency principle, applies to all aspects of the competitive solicitation. These principles are also interrelated. For example, oversight is effective only where there is transparency.*

*72. Transparency is the free flow of information to all parties. No party, particularly the affiliate, should have an informational advantage in any part of the solicitation process. The RFP and all relevant information about it should be released to all potential bidders at the same time. Instead of individually inviting specific bidders, the utility should allow all interested parties to bid on the RFP. All aspects of the competitive solicitation should be widely publicized. For example, the issuer can post the RFP on its website and issue a press release to that effect and/or advertise in the trade press. To compete effectively, [\*59] bidders should have equal access to data relevant to the RFP. Any communication between RFP issuer and bidder that is not part of the bid should be made available to all other bidders. For example, the answers to*

*clarifying questions should be released to all other bidders, but proprietary bid information should not be released.*

*74. If the RFP is to be designed through a collaborative process, the entire process should be widely publicized and open. An independent third party can ensure meaningful participation by nonaffiliates and eliminate characteristics that improperly give an advantage to the affiliate, e.g., the only acceptable interconnection point for a new nonaffiliate plant is at an affiliate's existing plant.*

*75. Negotiation may occur after the bidding; for example, when a shortlist has been compiled or a winner has been selected. If the affiliate is on the shortlist or wins, [\*60] it is important to ensure that the affiliate has no undue advantage resulting from its affiliate relationship. One way to prevent such an advantage from occurring is for the independent third party to be the RFP issuer's agent in the negotiation with the affiliate.*

#### *Definition principle*

*76. The product or products sought through the RFP should be defined in a manner that is clear and nondiscriminatory. The RFP should state all relevant aspects of the product or products sought. At a minimum, these aspects include capacity and term, but other characteristics are usually necessary, among them fuel type, plant technology (e.g., simple cycle gas turbine), and transmission requirements. If there are changes in the product specification, rebids should be allowed.*

*77. An RFP should not be written to exclude products that can appropriately fill the issuing company's objectives. This is particularly important if such exclusions tend to favor affiliates. This approach will enable us to address a subsequent section 203 application proposing to acquire assets from an affiliate.*

#### *Evaluation principle*

*78. To fulfill the evaluation principle, RFPs should clearly specify[\*61] the price and nonprice criteria under which the bids are evaluated. Price criteria should specify the relative importance of each item as well as the discount rate to be used in the evaluation. Non-price criteria should also specify the relative importance of items such as firm transmission reservation requirements, including acceptable delivery points; credit evaluation criteria, such as the bond rating; the plant technology if more than one technology is listed in the RFP; plant performance requirements, such as availability; and the anticipated in-service date if the plant needs to be constructed.*

**79. Naturally, these criteria are not meant to be exhaustive; they are merely illustrative. Keeping in mind that affiliates should have no informational advantage, all criteria should be specific and detailed so that all bidders can effectively respond to the RFP. Clear evaluation criteria will ensure that the RFP does not give an advantage to the affiliate.**

**80. RFP issuer and bidders will usually need to divulge commercially sensitive information in the solicitation process. Confidentiality agreements between the issuer and bidders can be signed to address this concern.**

**Oversight [\*62] principle**

**81. Effective oversight of competitive solicitations can be accomplished by using an independent third party in the design, administration, and evaluation stages of the competitive solicitation process. Ensuring that the third party is independent and granting it at the outset the responsibility of ensuring that these guidelines are followed throughout the process will also minimize perceptions of affiliate abuse. Minimum standards for assuring independence and the scope of the third party's role are set forth below.**

**82. A minimum criterion for independence is that the third party has no financial interest in any of the potential bidders, including the affiliate, or in the outcome of the process. n69 Preferably, the independence criterion would be the same as that of an ISO or RTO. n70 In this context, "independence" means that the third party's decision-making process is independent of the affiliate and all bidders. n71 Without such independence, the third party could be biased towards the affiliate in order to enhance its financial position. Obviously, a similar concern could arise regarding an actual or potential financial interest link between the third party[\*63] and any potential bidder. Independence can also be satisfied if the state commission has approved the selection of a third party on the basis of established independence criteria. In addition, the third party should not own or operate facilities that participate in the market affected by the RFP.**

**83. The independent third party should be able to make a determination that RFP process is transparent and fair, and that the RFP issuer's decision is not influenced by any affiliate relationships. For example, if the RFP issuer wishes to use a collaborative RFP design process, the independent third party should be the clearinghouse for comments by potential bidders on a draft RFP and should evaluate those comments as possible revisions to the RFP. The independent third party's role as the sole link for transmitting information between potential bidders and the RFP issuer would also help to ensure that the RFP design will not favor any particular bidder, particularly an affiliate. The independent third party should continue to be a conduit of information between**

*utility and bidders in determining which of the original bid responses are qualified bids or may be included in a short list.*

*84. At the evaluation stage of the RFP process, the third party should be able to credibly assess all bids based on both price and nonprice factors. It should be able to consider both generation asset bids and power purchase agreements. Also, it should be able to independently verify transmission[\*65] characteristics that may limit the suitability of certain alternatives. The third party should have access to the same information that the RFP issuer uses in its evaluation and should be able to independently verify its correctness. The third party should also be able to evaluate nonprice traits of various alternatives.*

**DISSENT:**

*Joseph T. KELLIHER, Commissioner dissenting in part:*

*I do not support the new competitive solicitation policy for consideration of dispositions of affiliated jurisdictional facilities under section 203 of the Federal Power Act (FPA). Since 1991, the Commission has applied the Edgar policy to consideration of power purchase agreements involving affiliates under section 205 of the FPA. The policy announced in this order would expand that policy and extend it to dispositions involving[\*67] affiliates.*

*In my view, the Commission's interest in proceedings under section 203 is fundamentally different from its interest under section 205. In a power purchase agreement involving an affiliate, the Commission has a legitimate interest in assuring that the process was fair, because we have a legal duty to assure just and reasonable rates and prevent undue discrimination or preference. In a section 203 proceeding, our interest is different because the legal standard is different. The Commission does not have a legal duty to assure that acquisitions of facilities are just and reasonable, or to prevent undue discrimination or preference in such dispositions. The public interest standard governs. While the Commission has discretion to determine just what that means, our interpretation must be guided by the fact that our legal duty to prevent undue discrimination and preference is limited to wholesale power sales and the transmission of electric energy in interstate commerce. n72 The disposition of a facility is neither. The Commission does not have a general charge to prevent any undue discrimination or preference in the electricity industry, but only in these two discrete areas. [\*68] n73*

*n73 See generally NAACP v. Federal Power Commission, 425 U.S. 662, 664 (1976) (holding that the legislative intent of neither the Federal Power Act nor the Natural Gas Act included a "public interest" in eliminating employment discrimination).*

*This competitive solicitation policy is designed to prevent an unfair solicitation in the acquisition of an affiliated facility by a public utility. I can appreciate that a competitive solicitation process can guard against a public utility overpaying or underpaying in such an acquisition. The Commission has a legal duty to prevent abusive self-dealing and cross-subsidies in jurisdictional services. However, it is the responsibility of a state commission, not this Commission, to ensure that a state-regulated utility does not subsidize an affiliate in the purchase of an asset. Like the presiding judge, I am not prepared to assume regulatory failure on the part of[\*69] state commissions. n74*

*n74 The competitive solicitation policy may also be designed to ensure that nonaffiliated generators have access to cash infusions from asset sales. If so, this seems to go beyond the pale. The Commission has a legal duty to promote competition, not competitors.*

*The Commission's interest in a jurisdictional disposition is on consideration of (1) the effect on competition, (2) the effect on rates, and (3) the effect on regulation. n75 The Commission previously found the proposed disposition in this order would have no adverse effect on rates and regulation, n76 and I see no reason to disturb those findings. The narrow question before the Commission in this order is whether the proposed transaction would have an effect on competition. In my view, the principal inquiry should be the impact of a proposed disposition on a public utility's market power. By this measure, the proposed disposition would not have a negative effect on competition.*

*I agree with the criticisms of the "safety net" theory offered by both the presiding judge n77 and Trial Staff. n78 Our competitive solicitations policy appears designed to guard against competitive impacts based on a theory that is speculative at best. I disagree with the competitive solicitations policy because I believe it is designed to solve a problem that does not exist, and does not advance the Commission's ability to assess legitimate market power issues.*

## **ACQUISITION BY UTILITY OR AFFILIATE OF INDEPENDENT GENERATOR** (Reverticalization)

The traditional vertically integrated electric monopoly consists of three primary components: generation, transmission, and distribution. However, in various regions of the country the electric utility industry has made a transition from a vertically integrated monopoly structure to a deverticalized, relatively competitive, market structure in which each utility's generation component, which accounts for 74% of the cost of electric power, could be functionally separated from its transmission and distribution components. The generation sector of the industry in these regions has been opened to retail competition, while high-voltage transmission (generally interstate) and interstate sales for resale remain federally regulated by FERC. In a series of orders, FERC has examined whether asset transfers subject to prior approval under Section 203 would satisfy its 1996 revised Merger Policy related to reviews of mergers and other dispositions of jurisdictional facilities based on the following criteria: (1) the effect on competition; (2) the effect on rates; and, (3) the effect on regulation..

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### ***Recent Cases Pertaining:***

EC04-53, Puget Sound Energy (Section 203)

#### ***Market Power Issues:***

- Puget filed on 1/14/04, pursuant to Section 203, for approval for acquisition of 49.85% interest in 249 MW gas-fired combined cycle EWG and associated transmission facilities from Frederickson Power, L.P.
- Section 203 issues raised were: (1) Impact on competition, (2) Impact on rates, and (3) Impact on regulation.

#### ***Status:***

- Commission initially found application to be deficient and requested information for a full competitive screen analysis.
- Case is notable because the Commission would not accept an abbreviated application lacking a full competitive screen despite the de minimus nature of the transaction.
- Commission approved acquisition on 4/23/04, finding that: (1) Acquisition not harmful to competition in PSE control area and the regional market for non-firm energy, short-term capacity or long-term capacity, (2) Acquisition of 137 MW by PSE would have a de minimus impact on market concentration given that BPA dominates the market with a 60% market share, (3) PSE is a net buyer in most months and therefore has limited capability of withholding capacity from the market, and (4)

BPA controls over 75% of the transmission grid in the region. 107 FERC ¶ 61,082, 61,261-63 (2004).¶

EC04-36, Sunbury Generation and Duquesne Power (Section 203)

***Market Power Issues:***

- On 12/8/03, Sunbury Generation and Duquesne Power filed a joint application pursuant to Section 203 requesting authorization for the sale of certain jurisdictional transmission facilities by Sunbury to Duquesne associated with 436 MW generation facility to be purchased by DP.
- Proposed acquisition is intended by DP to provide power to franchised utility affiliate to meet state-imposed provider of last resort obligations under a Commission approved PPA.
- Proposed transfer represents a *de minimus* transaction whereby Duquesne and its affiliates will own less than 0.6% of the more than 76,000 MW capacity in PJM.

***Status:***

- Commission approved transaction on 8/6/04. Cited *de minimus* nature of transaction. 108 FERC ¶ 61,160 (2004).

EC03-131, Oklahoma G&E (Section 203)

***Market Power Issues:***

- OG&E and NRG McClain filed a joint application pursuant to Section 203 requesting authorization for the sale of certain jurisdictional (merchant) facilities by NRG to OG&E.
- Issue of whether the proposed transaction violates the Commission's Merger Policy Guidelines for Section 203 applications.
- Issue of what will be the effect on competition, rates and regulation.
- Issue of what mitigation measures will be required to address increase in OG&E's horizontal and vertical market power resulting from the acquisition.

***Status:***

- In 12/8/03 Order, 105 FERC ¶ 61,297 (2003), the Commission found that the acquisition would increase OG&E's vertical and horizontal market power. Found that a Commission approved OATT is not a sufficient showing of a lack of vertical market power.

- OG&E filed proposed mitigation plan on 3/8/04. Staff filed testimony on 3/29/04 supporting mitigation measures proposed by OG&E.
- ALJ refused to certify OG&E Settlement Offer to Commission on 4/12. On 4/30 ALJ also refused to certify InterGen Settlement Offer to Commission.
- Commission issued order on 7/2/04 approving OG&E Settlement Offer with limited modifications. 108 FERC ¶ 61,004 (2004). Primary permanent mitigation measure approved by Commission is the expansion of OG&E's transmission capability through increased transmission investment. Interim mitigation measures will include OG&E making increased transmission available to intervenors through rescheduling and the establishment of an independent market monitor to oversee transmission operations prior to OG&E's full integration into the Southwest Power Pool.
- In concurring opinion, Chairman Wood stated that, although he agreed with the order, a preferable approach would have been to implement a measure such as regional economic dispatch. Reflects preference for structural versus behavioral mitigation measures.

EC02-113, Cinergy Services (Section 203)

***Market Power Issues:***

- In September 2002, Cinergy/PSI filed an application under Section 203 to transfer non-regulated affiliate gas-fired peaking plants to its regulated operations and dedicate the facilities to directly serving its Indiana native load customers
- The Indiana Utility Regulatory Commission authorized the transfer.
- Issue of whether a Section 203 transfer of merchant generation assets back to regulated affiliate negatively impact competition in the wholesale market—purely internal transfer of assets.

***Status:***

- Commission approved transfer in Order dated 2/4/03. 102 FERC ¶ 61,128 (2003). Commission found that intra-corporate transactions by their nature do not result in a change in market concentration levels in any relevant market. Consequently, the transfer would not affect competition under the current standards.
- The Commission, however raised "safety net" concern—the ability of a franchised utility to assume its affiliated merchant's generation when

market demand declines may give the affiliated merchant a safety net that merchant generators not affiliated with a franchised utility lack.

- Order denying requests for rehearing was issued on 9/17/04.

WDCDOCS 187334v1

## **When Market Pricing Recipients Change Their Status, What Happens?**

### **I. Background: Four-part test that the Commission uses to determine whether a public utility qualifies for market-based rate authority**

- A. generation market power
- B. transmission market power
- C. barriers to entry
- D. affiliate abuse/reciprocal dealing

### **II. Possible changes in status that can affect eligibility for market pricing**

- A. ownership or control of generation or transmission facilities or inputs to electric power production
- B. affiliation with any entity not disclosed in the filing that owns or controls generation or transmission facilities or inputs to electric power production or affiliation with any entity that has a franchised service area

### **III. Policy Questions**

- A. The regulations specifically reference "control" as well as ownership as a factor relied upon by the Commission
- B. Notice due in 30 days?
- C. FERC questions

"11. For example, should there be a threshold level of increases in generation (such as generation addition through acquisition, , self-build, long-term power purchases, repowering) that would trigger the reporting requirement? If so, what amount of increase in generation should trigger the reporting requirement?"

"12. Should the applicant have a reporting requirement if portions of the applicant's transmission system are taken out of service for a significant period of time (thus potentially affecting the scope of the relevant geographic market)? If so, what criteria should trigger this reporting requirement?"

"Should marketing alliances, brokering arrangements, tolling agreements or other sales-oriented arrangements be reported?"

D. Enforcement

"We we propose that this reporting requirement be incorporated into the market-based rate tariff of each entity that is currently authorized to make sales at market-based rates, as well as that of all future applicants."

**109 FERC ¶ 61,021**  
**UNITED STATES OF AMERICA**  
**FEDERAL ENERGY REGULATORY COMMISSION**

**18 CFR Part 35**

**(Docket No. RM04-14-000)**

**Reporting Requirement for Changes in Status  
For Public Utilities With Market-Based Rate Authority**

**(Issued October 6, 2004)**

...

**Background**

The Commission has a statutory duty under the FPA to ensure that rates charged by public utilities authorized to make wholesale sales in interstate commerce at market-based rates are just and reasonable.<sup>1</sup> The Commission uses a four-part test to determine whether to grant a public utility market-based rate authority. *That test examines whether the applicant or its affiliates possess the potential to exercise market power by considering generation market power, transmission market power, barriers to entry, and the potential for affiliate abuse or reciprocal dealing.* Sellers authorized to make sales at market-based rates are then required to file electric *quarterly reports* containing a summary of the *contractual terms and conditions* in every effective service agreement for market-based power sales and *transaction information* for their market-based rate sales during the most recent calendar quarter.<sup>2</sup>

The Commission has also required that market-based rate sellers report any changes in status that would reflect a departure from the

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<sup>1</sup> 16 U.S.C. § 824d(a) (2000).

<sup>2</sup> Revised Public Utility Filing Requirements, Order No. 2001, 67 FR 31043 (May 8, 2002), III FERC Stats. & Regs. ¶ 31,127 (Apr. 25, 2002). The required data sets for contractual and transaction information are described in Attachments B and C of Order No. 2001.

characteristics the Commission relied upon in its existing grant of market-based rate authority. When the Commission first granted market-based rate authorizations, it required *traditional utilities* that satisfied the Commission's initial market power review to file an *updated market power analysis every three years* to allow the Commission to monitor competitive conditions and to determine whether the applicants still satisfied our market power concerns.<sup>3</sup> *Power marketers*, on the other hand, were required to *promptly* notify the Commission of *changes in status*.<sup>4</sup> *Subsequently, the Commission has allowed market-based-rate sellers to choose between promptly reporting changes in status, filing a three-year update in lieu of reporting changes in status as they occurred,*<sup>5</sup> *or reporting such changes in conjunction with the updated market analysis.*<sup>6</sup> The Commission reserved the right to require such an analysis at any time. The Commission proposes to continue to reserve this right.

To carry out its statutory duty under the FPA to ensure that market-based rates are just and reasonable, the Commission must rely on market-based rate sellers to provide *accurate, up-to-date information regarding any relevant changes in status, such as ownership or control of jurisdictional facilities and affiliate relationships*. In contrast to when the Commission first began to authorize market-based rate sales, wholesale markets now have *many more sellers of different types (e.g., independent power producers, power marketers, affiliated generators)*. As markets have expanded and developed, both *the number and types of sellers have increased and the complexity of wholesale markets has increased*. Furthermore, market structure is rapidly evolving due to *restructuring, corporate realignments and new types of contractual and subcontracting arrangements, in which utilities increasingly grant other firms control*

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<sup>3</sup> See, e.g., Entergy Services, Inc., 58 FERC ¶ 61,234 (1992); Louisville Gas & Electric, 62 FERC ¶ 61,016 (1993).

<sup>4</sup> See, e.g., Citizens Power & Light Corporation, 48 FERC ¶ 61,210 (1989); Enron Power Marketing, 65 FERC ¶ 61,305 (1993); InterCoast Power Marketing Co., 68 FERC ¶ 61,248 (1994).

<sup>5</sup> See, e.g., Morgan Stanley Capital Group, Inc., 69 FERC ¶ 61,175 (1994).

<sup>6</sup> See, e.g., AEP Power Marketing, Inc., 76 FERC ¶ 61,307 at 62,516 (1996); Montaup Electric Co., 85 FERC ¶ 61,313 at 62,232 (1998); Sithe/Independence Power Partners, 101 FERC ¶ 61,210 at 61,907 (2002).

*and/or influence over managing various aspects of their business such as power marketing.* In light of these structural changes, the Commission has concluded that more timely reporting of changes in status is necessary.

We believe that, in today's electric industry, *granting market-based rate sellers the option to delay reporting changes in status by up to three years does not provide the Commission with sufficient information* to provide effective oversight of electricity markets.

Therefore, the Commission *proposes to eliminate the option to delay reporting changes in status until the next triennial review, or to file a triennial review in lieu of promptly reporting changes in status, and to standardize the change in status reporting requirement.* Accordingly, the proposed regulations would require that, *as a condition of obtaining and retaining market-based rate authority, all sellers will be required to timely report to the Commission any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority.*

With respect to the types of events that should trigger the reporting obligation, the Commission proposes that, as an initial matter, the following events would qualify as changes in status: *(1) ownership or control of generation or transmission facilities or inputs to electric power production; or (2) affiliation with any entity not disclosed in the filing that owns or controls generation or transmission facilities or inputs to electric power production or affiliation with any entity that has a franchised service area.*<sup>7</sup> Although the market-based rate change in status provision has not specifically referenced “control” of assets, we have historically considered control of an asset to be a factor on which we rely in granting market-based rate authority. *In order to eliminate any market uncertainty, we propose that the regulations specifically reference “control” as well as ownership as a factor relied upon by the Commission. In the Commission’s early orders granting market-based rate authority, we acknowledged that sellers may exercise market power through*

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<sup>7</sup> The Commission’s regulations define “affiliated companies” as “companies or persons that directly, or indirectly through one or more intermediaries, control, or are controlled by, or are under common control with, the [subject] company.” 18 CFR 101 (2004). *See also* 18 CFR § 161.2 (2004); Morgan Stanley Capital Group, *et al.*, 72 FERC ¶ 61,082 (1995).

*contractual arrangements granting them control of generation or transmission facilities just as effectively as they could through ownership.*<sup>8</sup> Similarly, the Commission's guidelines for the assessment of mergers and its generation market power analysis for market-based rate authority provide that, for the purposes of the market power analysis, the capacity associated with contracts that confer operational control of a given facility to an entity other than the owner must be assigned to the entity exercising control over that facility, rather than to the entity that is the legal owner of the facility.<sup>9</sup> In addition, with respect to notifications of changes in status, the Commission has found that *an entity controls the facilities of another when it controls the decision-making authority over sales of electric energy, including discretion as to how, when and to whom it could sell power generated by these facilities.*<sup>10</sup>

...

In addition to including this reporting requirement in the Commission's regulations, *we propose that this reporting requirement be incorporated into the market-based rate tariff of each entity that is currently authorized to make sales at market-based rates, as well as that*

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<sup>8</sup> See, e.g., Citizens Power & Light Corp., 48 FERC ¶ 61,210 (1989). In this order, we stated that: “[u]sually, the source of market power is dominant or exclusive *ownership* of the facilities. However, market power also may be gained without ownership. Contracts can confer the same rights of control. Entities with contractual control over transmission facilities can withhold supply and extract monopoly prices just as effectively as those who control facilities through ownership.”

<sup>9</sup> See AEP Power Marketing, Inc., *et al.*, 107 FERC ¶ 61,018 at P 95 (2004), *order on reh'g*, 108 FERC ¶ 61,026 at P 65 (2004); Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, 61 Fed. Reg. 68,595 (1996), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,044 (1996), *reconsideration denied*, Order No. 592-A, 62 Fed. Reg. 33,341 (1997), 79 FERC ¶ 61,321 (1997) (Merger Policy Statement); *see also* Revised Filing Requirements Under Part 33 of the Commission's Regulations, Order No. 642, 65 Fed. Reg. 70,983 (2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,111 at note 39 (2000), *order on reh'g*, Order No. 642-A, 66 Fed. Reg. 16,121 (2001), 94 FERC ¶ 61,289 (2001).

<sup>10</sup> El Paso Electric Power Co., *et al.*, 108 FERC ¶ 61,071 at P 14 (2004), *reh'g pending*.

*of all future applicants.* Market-based rate sellers would be required to submit a conforming provision to their market-based rate tariffs at the time that they file any amendment to their tariffs or (if earlier) when they apply for continued authorization to sell at market-based rates (e.g., in their three-year updated market power analysis). However, the Commission proposes that the obligation to report be effective at the time that the Final Rule becomes effective.

...

In § 35.27, paragraph (c) is added to read as follows:

**§ 35.27 Power sales at market-based rates.**

\* \* \* \* \*

(c) Reporting requirement. Any public utility with the authority to engage in sales for resale of electric energy in interstate commerce at market-based rates shall be subject to the following:

(1) As a condition of obtaining and retaining market-based rate authority, a public utility with market-based rate authority must timely report to the Commission any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. A change in status includes, but is not limited to each of the following:

(i) Ownership or control of generation or transmission facilities or inputs to electric power production, or

(ii) Affiliation with any entity not disclosed in the application for market-based rate authority that owns or controls generation or transmission facilities or inputs to electric power production or affiliation with any entity that has a franchised service area.

(2) Any change in status subject to paragraph (c)(1) of this section must be filed no later than 30 days after the change in status occurs.

## SUPPLY MARGIN ASSESSMENT

### PL02-8: Conference on Supply Margin Assessment

FERC allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry. Historically, it has required sellers with market-based rates to establish on a triennial basis their continued eligibility for market-based rate authority. In order to retain market-based rate authority a seller must prove to FERC every three years that it lacks market power.

On November 20, 2001, the Commission announced a new market power screen for generation, the Supply Margin Assessment (SMA), to replace the hub and spoke analysis, which the Commission has employed since beginning to grant market-based rates to public utilities in the 1980s. *AEP Power Marketing, Inc., et al.*, 97 FERC ¶ 61,219 at 61,969 (2001). In this Order, the Commission applied the SMA screen to market-based rate applications on an interim basis pending a generic review of new methods for analyzing market power, and established mitigation measures applicable to entities that fail the SMA screen.

- a. **The SMA Screen Policy:** If any portion of a power supplier's capacity is needed to meet peak load in the region where it supplies power it is considered a "pivotal" supplier and will not qualify for market-based rates unless it is a participant in a FERC-approved RTO. The SMA screen replaces the "hub and spoke" test for generation market power – a market share test that does not take transmission constraints and congestion into account. In a "hub and spoke" analysis the applicant computes its market share of installed and uncommitted generation in a particular market. While the Commission did not employ a bright line test, it looked to a benchmark for generation market power of whether a seller had a market share of 20 percent or less in each of the markets. When an applicant is pivotal, it is in a position to demand a high price above competitive levels and be assured of selling at least some of its capacity. An applicant will be pivotal if its capacity exceeds the market's surplus of capacity above peak demand--that is, the market's supply margin.
- b. Most parties have agreed that the hub and spoke test needed replacement and their comments on the SMA screen have focused on (1) whether to include capacity committed under long term contract in the screen, (2) whether the SMA screen adequately detects collusive activity and (3) whether FERC should eliminate the SMA exemption for sellers participating in an RTO-monitored market. The California PUC has opposed the RTO exemption. A final order is still pending.

The Commission subsequently postponed implementation of the mitigation for spot market energy sales and, on August 23, 2002, initiated proceedings in Docket No. PL02-8, requesting written comments on the SMA screen and related mitigation measures. This proceeding addressed the following questions:

- (1) What generation market power screen test should the Commission use to determine whether an Applicant should be granted market-based ratemaking authority?
- (2) Should the generation screen test only focus on uncommitted capacity, i.e., capacity that is not committed for firm service retail and wholesale sales?
- (3) What is the appropriate mitigation for an applicant found to have generation market power?
- (4) Should an applicant that is part of an RTO/ISO be exempt from the market power screening process?

On April 14, 2004, following a technical conference, the Commission issued an order implementing a new two stage market power screening process. *AEP Power Marketing, Inc., et al*, 107 FERC ¶ 61,018 (2004):

- Stage 1 of this new process requires the applicant to demonstrate that it passes Pivotal Supplier and Market Share Screens excluding committed capacity. If the Applicant fails either screen, it can accept Commission-approved Default Cost-Based Rates or go to Stage 2.
- Stage 2 requires the Applicant to either pass a Delivered Price Test or submit a Mitigation Plan acceptable to the Commission. The Mitigation Plan must satisfy the Commission that despite the Applicant's failure to pass the screens demonstrating lack of market power, the Applicant has fashioned sufficient protections or agreed to sufficient conditions to ensure that it cannot exercise market power.

The RTO/ISO exemption, which was opposed by a number of state commissions, was eliminated from the new process. On July 8, 2004, the Commission issued an Order On Rehearing, 108 FERC ¶ 61,026 (2004), that maintained the framework of market screens adopted in its April 14<sup>th</sup> Order.

## **Regional State Committees: FERC Treatment**

*Southwest Power Pool, Inc.,*  
**108 F.E.R.C. para. 61,003 (July 2, 2004)**  
**"Order on Compliance Filing"**

### **I. RSC Responsibilities**

- A. RSC should have primary responsibility for determining regional proposals and the transition process in the following areas:
  - 1. whether and to what extent participant funding would be used for transmission enhancements;
  - 2. whether license plate or postage stamp rates will be used for the regional access charge;
  - 3. FTR allocation where a locational price methodology is used; and
  - 4. the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers' existing firm rights.
- B. The RSC should determine the approach for resource adequacy across the entire region.
- C. With respect to transmission planning, the RSC should determine --
  - 1. whether transmission upgrades for remote resources will be included in the regional transmission planning process, and
  - 2. the role of TOs in proposing transmission upgrades in the regional planning process.

### **II. RSC-SPP Relations**

- A. If the RSC reaches a decision on the methodology that should be used, SPP would file this methodology pursuant to section 205 of the FPA.
- B. The SPP can also file its own proposal under section 205.

- C. The RSC "has primary, but not sole, responsibility for determining the proposals indicated in the February 10 Order, to the extent that SPP also can file its own proposals." (para. 94)

### **III. FERC-State Relations**

- A. FERC's "purpose in approving an RSC is not to usurp state authority, but, rather, to facilitate state consensus on certain regional issues and a partnership between this Commission and state commissions." (para. 90)
- B. There is no unlawful delegation because "like any proposal filed pursuant to section 205, proposals filed at the behest of the RSC are subject to Commission review and disposition." (para. 91)

### **IV. FERC-SPP Relations**

There is no infringement on SPP's own section 205 filing rights. "As noted above, SPP agreed to file with the Commission certain regional proposals that may be developed by the RSC. In addition to RSC proposals, SPP may file its own proposals." (para. 93)

### **V. Comments and Questions**

- A. What does "determine" mean, in these contexts:
  - 1. "determining regional proposals" (para. 83)
  - 2. "determine the approach for resource adequacy across the entire region" (para. 84)
  - 3. "determine the approach for resource adequacy across the entire region" (para. 84)
  - 4. "determine ... the approach for resource adequacy across the entire region" (para. 84)
- B. Suppose the RSC makes a filing and the SPP makes an alternative filing. Suppose further that the substance of both filings is acceptable under the Federal Power Act.
  - 1. Can FERC choose either one and reject the other?

2. Or is FERC bound to accept the RSC-preferred filing while rejecting the SPP-preferred filing?
  3. Or is FERC bound to accept the SPP-preferred filing while rejecting the RSC-preferred filing?
  4. What FPA provision applies?
- C. What if a RSC majority votes to have SPP make a filing, but a RSC minority opposes that filing? Does the SPP filing made pursuant to the RSC majority's directive automatically receive FERC's approval (assuming it is lawful), whereas the position taken by the minority RSC members is disregarded?

Note: Under the FPA, deference by FERC means that FERC must accept the filing if it is not unlawful (i.e., not just and reasonable, and not unduly discriminatory or preferential), even if FERC prefers another approach.

- D. Concerning para. 92: If the Commission has conditioned its approval of an RTO on the SPP's agreeing to make the RSC's filings, is the SPP's agreement to do so "voluntary?" Is the legal situation then different from FERC's directly ordering the RTO to make filings prescribed by the RSC?

*Southwest Power Pool, Inc.,*  
Docket Nos. RT04-1-002, ER04-48-002, 108 F.E.R.C. para. 61,003 (July 2, 2004)  
"Order on Compliance Filing"  
[direct quotes and original para. numbers, footnotes omitted]

82. In the February Order, the Commission stated that it fully supported the creation of a Regional State Committee (RSC) within the SPP footprint. We stated that a representative RSC will benefit SPP and market participants by instituting a *partnership* between this Commission and state commissions, through which regional issues can be addressed. However, we found that the SPP's and Supporting Commission's proposal concerning RSCs did not adequately address several important issues.

83. We stated that the RSC should have *primary responsibility for determining regional proposals* and the *transition process* in the following areas: (1) whether and to what extent *participant funding* would be used for transmission enhancements; (2) whether *license plate or postage stamp* rates will be used for the regional access charge; (3) *FTR allocation* where a locational price methodology is used; and (4) the *transition mechanism* to be used to assure that *existing firm customers receive FTRs equivalent to the customers' existing firm rights*. We stated that, *if the RSC reaches a decision* on the methodology that should be used, *SPP would file this methodology* pursuant to section 205 of the FPA, and that *SPP can also file its own proposal* under section 205.

84. The Commission further stated that the RSC should *determine the approach for resource adequacy across the entire region*, and that, with respect to transmission planning, the RSC should *determine whether transmission upgrades for remote resources will be included in the regional transmission planning process*, as well as the *role of TOs in proposing transmission upgrades in the regional planning process*.

85. On rehearing, State Regulators argue that state participation in the RSC is voluntary, and that the RSC itself cannot limit or usurp state authority. They assert that the states have jurisdiction over transmission planning, bundled native load customers, and reliability issues. *They further assert that, to the extent participating states have approved of an RSC decision on these and other asserted state-jurisdictional issues, neither SPP nor the Commission may override that RSC decision.*

86. On rehearing, the Kansas Commission and Golden Spread argue that the Commission ***unlawfully delegated its responsibilities*** under the FPA to the RSC, by giving the RSC decision-making authority over whether and to what extent participant funding would be used for transmission enhancements, whether transmission upgrades for remote resources will be included in the regional transmission planning process, and the approach for resource adequacy across the SPP region. The Kansas Commission and Golden Spread argue that the RSC should assume the role of an ***advisory body*** to the independent SPP Board of Directors. The Kansas Commission seeks Commission clarification that any RSC initiatives are ***subject to Commission review*** and that the RSC is ***accountable to both SPP and the Commission***.

87. To that end, the Kansas Commission further argues that the Commission failed to provide guidance regarding the appropriate relationship between the RSC and SPP Board of Directors, or regarding the preferred voting structure of the RSC. Accordingly, the Kansas Commission argues that the Commission failed to ensure ***proper independence of the SPP Board of Directors***, given that ***members of the RSC have a strong vested interest in the outcome of SPP's energy markets***.

88. In addition, the Kansas Commission argues that the February 10 Order ***erroneously allows the RSC to compel SPP to make a section 205 filing***. The Kansas Commission contends that the RSC should not have the "primary" responsibilities indicated in the February 10 Order and that the Commission should have directed a hearing regarding the RSC's role.

90. We will clarify the issues concerning the RSC. As set forth above, the Commission has addressed issues concerning transmission planning, bundled retail load and reliability in a manner consistent with its jurisdiction. Moreover, we emphasize that, ***our purpose in approving an RSC is not to usurp state authority, but, rather, to facilitate state consensus on certain regional issues and a partnership between this Commission and state commissions***.

91. With regard to arguments that we unlawfully delegated to the RSC our responsibilities under the FPA to determine just and reasonable rates, terms and conditions, we emphasize that, ***like any proposal filed pursuant to section 205, proposals filed at the behest of the RSC are subject to Commission review and disposition***.

92. We further dismiss as moot arguments that the February 10 Order erroneously allows the RSC to compel SPP to make a section 205 filing. We emphasize that ***SPP voluntarily filed the RTO application*** at issue in this proceeding. ***In acting on that application in the February 10 Order, we required SPP to allow the RSC***

*to direct certain section 205 filings. By deciding to proceed with its RTO application, SPP has voluntarily agreed to file with the Commission, pursuant to section 205, certain regional proposals that may be developed by the RSC. Because SPP has so agreed, the February 10 Order language on this issue no longer governs.* Accordingly, since the factual predicate upon which these rehearing arguments were based no longer exists, we dismiss these arguments as moot.

93. We *reject arguments that the RSC is infringing on SPP's own section 205 filing rights.* As noted above, *SPP agreed to file* with the Commission certain regional proposals that may be developed by the RSC. In addition to RSC proposals, SPP may file its own proposals. Moreover, in our order on SPP's compliance filing to the February 10 Order, we accepted proposed language in section 7.2 of SPP's Bylaws, which provides that no RSC proposal "shall prohibit SPP from filing its own related proposal(s) pursuant to [s]ection 205."

94. With regard to arguments that the RSC should be advisory only, we find that no new arguments were raised on rehearing that were not addressed and rejected in the February 10 Order. In any case, we emphasize that the RSC *has primary, but not sole, responsibility* for determining the proposals indicated in the February 10 Order, to the extent that SPP also can file its own proposals.

## RECENT RTO APPROVAL DECISIONS

In Order No. 888 and in Order No. 2000, the Commission encouraged the formation of regional entities that administer transmission tariffs and control the transmission facilities of their member transmission-owning entities. In these Orders, FERC delineated eleven principles defining the operations and structure of a properly functioning Independent System Operator (“ISO”), as well as certain functions and characteristics of a Regional Transmission Organization (“RTO”). Over the past years, the Commission has issued a series of Orders approving several ISOs and RTOs which have since commenced operations. Since last year’s NARUC meeting, FERC has approved the formation of the New England RTO, which went into operation on February 1, 2005.

**Framework.** FERC regulation of Voluntary RTOs -- *Atlantic City Electric Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002)

- (i) FERC has no Section 203 power to regulate formation of RTOs
- (ii) FERC has no Section 203 power to regulate utility decisions to exit an RTO
- (iii) FERC has authority to regulate voluntarily-executed RTO agreements
  - a. It can regulate the terms and conditions of the RTO(*Atlantic City Electric v. FERC*, and *Central Iowa Power Cooperative v. FERC*).
  - b. It can regulate the termination of an RTO agreement or the departure of a member
  - c. It can enforce voluntarily accepted obligations even if it could not mandate them at the outset. *Cleveland Electric Illuminating Co.*, 11 FERC ¶ 61, 114 (1980) If a state opposes a utility’s participation in an RTO this raises PURPA issue of FERC’s power to preempt state law.

FERC’s approval of the New England RTO addressed several of the issues related to the terms and conditions it will impose on a voluntarily-formed RTO. These are discussed below.

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### ***Recent Cases Pertaining:***

#### RT04-2, Request for Approval of a Regional Transmission Organization for New England.

- On October 31, 2003, ISO New England and the New England Transmission Owners filed an application with the Commission for approval of an RTO for New England, pursuant to **Section 205** of the Federal Power Act.

- On March 24, 2004, FERC granted RTO status to ISO New England and the New England transmission owners pending acceptance of certain conditions. 106 FERC ¶ 61,280 (2004). In this Order, the Commission held that the New England transmission owners are

permitted to withdraw from their existing agreements governing the operation of NEPOOL in order to file the necessary replacement agreements to establish the RTO. *Id.* at 62,039.

- On November 3, 2004, the Commission conditionally approved the ISO-NE Tariff, which includes mostly provisions previously accepted by the Commission under the ISO-NE/NEPOOL arrangements. 109 FERC ¶ 61,147 (2004). ISO-NE's Tariff remained in effect until it began operation as an RTO on February 1st.

Among the issues :

- **Termination Rights.**

“Specifically, proposed Section 10.01(b) of that agreement would have permitted a Transmission Owner to unilaterally withdraw from the ISO-NE RTO upon the occurrence of certain stated conditions. We rejected the Filing Parties' proposal because it would have prohibited any meaningful review by the Commission under Section 205 of the FPA relating to a Transmission Owner's withdrawal from the ISO-NE RTO, even in those instances where revisions to the ISO-NE RTO's operating agreements would have been necessary.” (P. 30)

Moreover, we found that the Filing Parties' proposal was inconsistent with our policy regarding RTO/ISO access and withdrawal rights. Specifically, we noted that the RTO/ISO Access and Withdrawal Rights Policy Statement held, as a matter of Commission policy, that arrangements to join or exit an RTO or ISO must be reviewed by the Commission in the context of filings made under Section 205. We also noted that this review is necessary in order to determine whether all of the elements contained in the filed arrangements meet the principles of Order No. 2000 and are otherwise just and reasonable under Section 205 of the FPA. Accordingly, we required the Filing Parties to revise Section 10.01(b) of the Transmission Operating Agreement.” (P. 31)

“The Transmission Owners' proposed language would permit "any termination or withdrawal [to become] effective unless the [Commission] finds that such termination or withdrawal is contrary to the public interest under the *Mobile-Sierra* Doctrine." We cannot accept this limitation. *Section 205 review (as required by the March 24 Order) means that the Commission will determine whether an action under review is just and reasonable. Intervenors asserted in response to the Filing Parties' initial proposal, and we agree on rehearing, that, a full, meaningful review by the Commission of a requested withdrawal from, or*

*termination of, the ISO-NE RTO would not be possible where the Transmission Owner's rights to do so are governed by a standard of review that limits the application of the just and reasonable standard.* Accordingly, we will require the Filing Parties to modify Section 10.1(f) of the Transmission Operating Agreement to make clear that while a challenge to a Section 10.01(f) request made by any of the parties to the Transmission Operating Agreement will be subject to the Mobile-Sierra doctrine, as proposed by the Transmission Owners, the Commission's own review of a requested withdrawal or termination will be made under Section 205 of the FPA, i.e., the Commission's own review will not be limited by application of the Mobile-Sierra doctrine. (P. 40) (emphasis added)

We also deny the Transmission Owners' argument, on rehearing, that our review of a requested withdrawal from the ISO-NE RTO should not take into consideration our RTO formation policies under Order No. 2000. In considering the justness and reasonableness of any filing made under Section 205, including an RTO withdrawal filing, the Commission is required to consider its policies and precedents, as may be relevant to the issues presented for our review. *Although participation in an RTO is voluntary, a transmission owner's withdrawal can have a substantial impact on other market participants and the markets themselves. In these circumstances, the policies enunciated in Order No. 2000 would be relevant and must be considered.*" (P. 41) (emphasis added)

- **Reversionary Interests**

Following the start-up of the ISO-NE RTO, neither NEPOOL nor any NEPOOL Participant retained any interest in any tangible assets of the ISO-NE RTO. (P 15). The tangible assets constituting the NEPOOL Assets, under the Interim ISO Agreement, were transferred to the ISO-NE RTO as of the ISO-NE RTO Operations Date. (P. 24)

- **Governance Structure**

“In the March 24 Order, we found that the Filing Parties' proposed governance structure for the ISO-NE RTO generally met our RTO independence requirement, subject to three conditions. First, we required the Filing Parties to include alternative energy suppliers as a sixth voting sector in the ISO-NE RTO stakeholder advisory process. Second, we modified the Filing Parties' proposal regarding the ISO-NE RTO's obligation to include alternative stakeholder proposals when making a Section 205 filing. Finally, we required that in nominating and electing a new ISO-NE RTO

board, at least one new nominee must be named under those circumstances in which a second slate must be nominated.” ( P. 26)

- **Allocation of Section 205 Filing Rights between an RTO and Transmission Owners**

FERC’s policy is largely to defer to the agreement of the parties, subject to FERC’s determination that the ISO’s independence is preserved:

We will deny the Transmission Owners' rehearing request with regard to the ISO-NE RTO's ultimate authority to reschedule transmission outages for economic or reliability considerations. We agree with the Transmission Owners that the Commission's reasoning in giving the ISO-NE RTO ultimate authority to reschedule outages for economic or reliability considerations was not based on our directives in Order No. 2000. However, as we stated in the March 24 Order, allowing the Transmission Owners any influence in the rescheduling of transmission outages creates an inherent conflict of interest, especially where the Transmission Owner also owns or controls generation resources or has load serving obligations. (P. 140)

- **Mobile Sierra Protections for Transmission Owners**

FERC found that what is determinative in deciding whether to allow Mobile Sierra protection for provisions of an RTO agreement or require the provisions to be embodied in a tariff subject to just and reasonable rate review is whether the “provisions primarily affect the rights and interests of the Filing Parties” (P. 76) or will have a “significant effect on market participants that are not parties to these agreements or on reliable operation of the New England market.” (P. 80) If the latter, the provisions are not entitled to *Mobile Sierra* protection. Applying this standard, FERC concluded that contract provisions related, e.g. to collection and disbursement of payments, transmission planning and expansion, grandfathered agreements and municipal tax exempt status (PP. 77-80) could receive *Mobile Sierra* protection, while provisions related to termination of the agreement and dispute resolution procedures should be included, instead, in the RTO OATT. (PP. 85, 90)

- **Rights of Independent Transmission Companies**

“The March 24 Order found that the Filing Parties' proposed procedures regarding the establishment and operation of Independent Transmission Companies within the ISO-NE RTO framework was generally consistent with the Commission's policies and precedents, subject to the following conditions: (i) the re-filing of the relevant procedures as revisions to the ISO-NE RTO OATT; (ii) clarification that an Independent Transmission Company's authority over rate discount matters was subject to the rate discount authorizations set

forth in the ISO-NE RTO OATT; (iii) clarification that the ISO-NE RTO would be given the final say over planning procedures; (iv) clarification regarding an Independent Transmission Company's authority over the development of Reliability Must Run related costs; and (v) clarification regarding the circumstances under which a project identified by an Independent Transmission Company could be incorporated into the ISO-NE RTO's Regional System Plan; and (vi) clarification regarding an Independent Transmission Company's authorization over line loss responsibility determinations.” (P. 91)

- **Scope and Configuration Requirements**

In the March 24 Order, we found that the ISO-NE RTO generally met our RTO scope and regional configuration requirements, subject to conditions concerning certain interregional seams issues. Specifically, while we noted the Filing Parties' commitment, to date, to address inter-regional seams issues on a regional basis, under a Interregional Coordination Agreement entered into by ISO-NE and the New York ISO, we also found that the timetable for addressing these issues must be pursued by the parties without delay. Accordingly, *we conditioned our approval of an ISO-NE RTO on the Filing Parties' development of a more comprehensive seams agreement with the New York ISO.* (P. 55)

Among other things, we required the Filing Parties to address in their revised seams agreement *specific milestones and timelines for resolution of all remaining seams issues within one year of the date of the Filing Parties' First Compliance Filing.* We also required the Filing Parties to submit a proposal for *eliminating Through-and-Out Service Charges between the ISO-NE RTO and the New York ISO within six months of the date of the Filing Parties' First Compliance Filing.* Finally, we stated that because the New York ISO has significant trade with its RTO neighbor to the south, PJM Interconnection, L.L.C. (PJM), the Filing Parties should also *explain in their First Compliance Filing the role that PJM could play in the resolution of broader, regional seams issues.* We stated that the Filing Parties should identify the specific remaining seams issues that require the participation and involvement of PJM. (P. 56) (Emphasis added)

RM04-12, Notice of inquiry re Financial Reporting & cost accounting, oversight & recovery practices for Regional Transmission Organizations & Independent System Operators.

- On September 16, 2004, the Commission issued a Notice of Inquiry, 108 FERC ¶ 61,237 (2004), requesting comments relating the following issues:

- (1) whether changes needed to the Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act (UsofA), 18 C.F.R. Part 101, to better account and report RTO and ISO financial information to the Commission, in order to provide greater transparency of transactions and business functions affecting these entities and their member transmission-owning public utilities,

- (2) whether RTOs and ISOs have appropriate incentives to be cost efficient, and

- (3) whether the Commission's rate review methods for RTOs and ISOs are sufficient.

- Comments were filed in the case, and it is currently pending.

WDCDOCS 187339v1

# State Commission Access to the Market Data Held by the Regional Transmission Organization or Independent Market Monitor<sup>1</sup>

## I. Procedural Background

A. In a August 6, 2004 Order,<sup>2</sup> the Commission

1. "reject[ed] Sections 38.9.4 and 54.3, pertaining to the Midwest ISO's and the IMM's authority to share information with state regulatory commissions and other Authorized Requestors" (para. 561); and
2. directed Midwest ISO "to more closely align its confidentiality proposal with PJM's." (para. 557)

B. The Commission also stated:

561. ... Neither the Midwest ISO's filing nor the intervenors' comments make clear why OMS and the states seek access to data that is comparable to the Commission's access, how they will keep that data confidential, or for what purpose they will use the data. The Midwest ISO's proposal is broader than the recently accepted PJM confidentiality policy, and we believe that the two SOs should have comparable rules as they move toward a joint and common market. We therefore instruct the Midwest ISO to work with its stakeholders, and with PJM if it desires, to develop a revised proposal. The revised proposal should include the type of non disclosure agreement recently approved for PJM. Such an agreement will harmonize Authorized Requestors' individual obligations to protect data.

562. The revised proposal should delete the Midwest ISO's proposal to permit Authorized Requestors to disclose Confidential Information to other Authorized Requestors....

C. Explaining his concurrence with the portion of the August 6 Order rejecting Midwest ISO's proposal to share data with state commissions, Commissioner Kelliher stated that

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<sup>1</sup> This outline is drawn from a pleading filed with FERC by the Organization of MISO States (OMS) in February 2005, on which the author assisted OMS.

<sup>2</sup> "Order Conditionally Accepting Tariff Sheets To Start Energy Markets And Establishing Settlement Judge Procedures," 108 FERC 61,163 (Aug. 6, 2004).

[i]n my view, in order to justify approval of Midwest ISO's proposed procedures for distributing confidential information to these state entities, Midwest ISO would need to demonstrate that (1) providing the state entities with confidential information possessed by Midwest ISO and the IMM is necessary for the state entities to discharge their legal responsibilities, and (2) the state entities cannot obtain such information under state law.

- D. In a September 30, 2004 Order,<sup>3</sup> the Commission granted the Organization of MISO States (OMS) request to make an offer of proof regarding the Midwest ISOs data confidentiality proposal. September 30 Order at para. 2.
- E. That offer would demonstrate that --
  - 1. state commissions have the statutory authority to safeguard confidential data;
  - 2. state commission access to confidential information will advance the Commissions and state commissions common goals for wholesale market reform while preserving the state commissions legitimate needs. *Id.* at para. 9.

## II. Legal Framework

- A. Under Section 205 of the Federal Power Act, a public utility has a right to approval of its proposal if that proposal is just and reasonable and not unduly discriminatory.
  - 1. MISO, a public utility, proposed to FERC a method of data sharing with the states and with OMS. The legal question before FERC is whether the data access provisions fall into the two forbidden legal categories: unjustness and unreasonableness, or undue discrimination. If the proposal falls outside these categories, the Commission has no legal authority to reject it, even if the Commission would prefer another one.
  - 2. The existing FERC precedent does not connect data access concerns to one of these statutory categories.

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<sup>3</sup> Order Granting Rehearing For Purpose Of Further Consideration, Granting Opportunity To Make Offer Of Proof And Holding Compliance Requirement In Abeyance, 108 FERC 61,321 (2004). The September 30, 2004 Order granted rehearing on its Order of August 6, 2004.

- a. In its August 6, 2004 Order, the Commission cited no legal basis for its rejection of Sections 38.9.4 and 54.3 of the proposed Open Access Transmission and Energy Markets Tariff (TEMT) (regarding the authority of Midwest ISO and the Independent Market Monitor (IMM) to share information with state regulatory commissions and other Authorized Requestors). The Commission's explanation consisted of a two paragraphs, paras. 561 and 562, quoted above.
  - b. In footnote 328 to this passage, the Commission cited its rejection of a protesters similar proposal in conjunction with PJMs new information sharing policy. The Commission noted that allowing requestors to share data without PJMs knowledge would make it more difficult for PJM to keep track of who has data. *See PJM Confidentiality Order, PJM Interconnection, L.L.C.*, 107 FERC 61,322 (2004) at Para. 3537. The PJM Order as well did not contain any citation to the just and reasonable standard.
- B. Is the potential harm to wholesale competition substantial evidence that state data access is unjust and unreasonable or unduly discriminatory?
1. One argument against state commission data access is as follows:
    - a. States' data access would discourage wholesale generators from serving the Midwest market.
    - b. With fewer wholesale generators in the market, market-based rates would be subject to less competitive discipline.
    - c. The absence of this competitive discipline would cause the market based rates to exceed just and reasonable levels.
  2. In evaluating the merits of this argument, consider the following:
    - a. Is there a factual basis for finding that generators would remove themselves from a profitable wholesale market on the grounds that data would be available to state commissions who were legally obligated to keep the data confidential.
    - b. Is there a way to determine whether the number of generators who withdrew would be sufficiently large so as to cause wholesale prices to rise unreasonably due to diminished competition?

- c. Even if all generators with data discomfort withdrew from the market, would rates necessarily become unjust and unreasonable, given FERC's authority to replace market pricing with traditional cost-based pricing?

### **III. Relationship between specific data sought by state regulators and specific state responsibilities**

#### **A. Types of data sought**

1. Hourly bids, schedules, offers, actual output of resources, imports, and exports from the Midwest ISO
2. Reserved and scheduled transmission service
3. Transmission limits
4. Hourly flows over monitored transmission facilities
5. Dispatch of generation for energy, regulation, frequency, or other operational orders
6. Redispatch of generation
7. Logs of transmission service requests
8. Logs of generation interconnection requests
9. Generation and transmission outage data
10. Data on complaints by market participants
11. Production costs
12. Opportunity costs
13. Generation logs
14. Bidding arrangements

#### **B. Retail regulation requires attention to wholesale inputs**

1. Retail costs reflect the costs of wholesale inputs. Although wholesale inputs are regulated by FERC, the retail seller's choice among those inputs is regulated by the states. That state regulation includes not only whether a retail utility chose prudently from the menu of wholesale options, but also whether the utility should have entered the wholesale market at all.
2. Data on the operation of regional wholesale electricity markets helps states ensure that their retail utilities are operating efficiently in all these markets.
3. To assess their utilities' mix of short-term and long-term purchases and sales, they must understand short-term and long-term markets.

4. Where a utility has acquired surplus to prepare for future demand increases, the state must assess whether the utility is properly marketing that surplus in short-term or interruptible sales.
5. The state must determine if the utility is economically timing its plant utilization and maintenance schedule in light of the cost of wholesale market replacement power.
6. The states then must look beyond wholesale market activity to wholesale market infrastructure, including the adequacy of transmission and generation resources. That adequacy affects the extent to which it is prudent for the utility to rely on wholesale power rather than to generate its own power; and ultimately whether its utilities should remain in the Midwest ISO.

C. Specific examples of state needs

1. Resource adequacy

- a. At the FERC level, long-term generation planning obligations rest with the wholesale seller, not with the agency; and these obligations rest with the wholesale seller only when that seller has volunteered to accept them. There is no FPA obligation to conduct long-term planning. A wholesale seller having a 30-year requirements contract to a municipal or cooperative customer must plan for and procure resources sufficient to satisfy that contract.
- b. Those states with traditional regulation, in contrast, have the legal responsibility to address adequacy in all aspects of the electric sales process. In state regulatory practice, a utility's generation obligation is defined not by individual contracts but by the statutory obligation to serve, for the long term.
- c. The state commission therefore must address all aspects of generation planning, including:
  - (1) the mix of utility-owned versus vs utility-purchased resources, short-term and long-term purchases, baseload, intermediate and peaking plants, fuel sources and generation and demand side management
  - (2) reserve margins

- (3) location of new plants, and the relationship of that location to transmission availability
- (4) the timing of acquisitions, life extensions, environmental upgrades and plant retirements
- (5) whether newgeneration resources should be utility-owned or purchased at wholesale
- (6) the concentration of ownership in, and consequent competitiveness of, generating plants in the wholesale market

## 2. Distribution

- a. States must assure the integration of distribution facilities with transmission facilities. Integration includes planning and operation. Planning requires sufficient distribution assets in the right locations, so as to connect load with the transmission system.
- b. Some states, therefore, must predict not only where load will grow, but also where transmission and transmission substations will be built. Those locations depend, in turn, on where generation will be built and used. Even a distribution-only regulator would benefit from knowledge of wholesale generation markets.

## 3. Demand response management

- a. Demand response management takes many forms. Time-differentiated pricing, interruptible tariffs, end-use load control and investment in conservation equipment are among them. Each is a retail customer option; each falls exclusively within state jurisdiction. Each comes with a cost -- a cost which the state commission must weigh against the benefits. The possible benefits include improving price signals to wholesale generation markets and shaving price spikes.
- b. But the state commission must put a dollar figure on these benefits in order to compare them to costs. Without data on the behavior of wholesale markets, the state commission cannot calculate the benefits; the state cannot know how much price signal improvement is necessary or the magnitude of exposure to price spikes if there is no investment.

4. Maintenance schedules and outages
  - a. Since the central purpose of retail regulation is assurance of reliable supply at reasonable prices, the frequency of maintenance outages and unplanned outages is a state concern. Whether these outages occur in the generation, transmission or distribution sectors, they are inputs to the retail experience and therefore of statutory concern to the state commission.
  
5. FTRs and prudence review
  - a. For states to assess the prudence of a load serving entity's management of its FTR portfolio, state commissions must have detailed information on the operations of the wholesale market. Each utility's ability to minimize its costs will depend in part on its skill and judgment in managing FTRs. Because the utility's revenue requirement will include FTR costs and revenues, the retail rate regulator will need data on the inputs and options relating to FTRs. Because the FTR market is regional, the prudence analysis must be regional.
  - b. The state role here is not confined to ratemaking. A state's review process will need to consider projections of FTR costs. To arrive at those projections, the state will need data on the behavior of all market participants.
  
6. Seams
  - a. RTO boundaries do not match economic trading areas. FERC and the states must contend with four distinct sets of boundaries: RTO boundaries, retail service territory boundaries, regional reliability council boundaries, and state political boundaries. At least the state political boundaries remain unchanged. But mergers, and utility departures from one RTO to another, create multiple moving targets. Notwithstanding these difficulties, it remains FERC's and the state's responsibility to act in concert to ensure a reliable and economic wholesale market, regardless of seams.
  - b. The consumer interest is ill-served when states find themselves in opposition over seams, forcing the FERC to declare winners and losers in a zero sum game. Nor are states helped by having to deal with each other in the dark. Data can soften the edges of disputes by identifying

logrolling opportunities, across regions and across periods of time. Data allows negotiators to focus not only on immediate cost shifts but future benefits. Data can change the game from allocating costs to dividing up benefits. The more states know, the better they can deal with the seams issues; and the better they can deal with seams issues, the sooner the seams will be resolved.

7. Transmission pricing

- a. States do not set prices for unbundled transmission service. But, in many cases they do determine whether retail utilities may transfer transmission assets to RTOs, for how long and under what conditions. And each state decides its retail utility's retail rate recovery of RTO transmission charges. Further, each state through its individual procedures (e.g., IRP, siting and certificating processes), determines whether, where and when transmission is built.
- b. Thus there are three major state commission decisions: transmission transfer, retail rate recovery of transmission related charges, and construction of transmission related infrastructure. A state commission cannot satisfy its statutory public interest obligations without finding that benefits exceed costs or, for some states, that no detriment will occur. In each of these three areas, the costs will be known and tangible, at least in part. Without a finding of benefits or, at least no detriment to the public, an approval will prove elusive. And there cannot be findings for benefits without supporting data.

D. The success of FERC-jurisdictional wholesale markets depends on state decisions about the level of utility participation in those markets

1. For wholesale markets to develop competitively, retail utilities must buy from those markets rather than build their own generation. Where the state commission is obligated by state law to ensure reasonable rates, the state commission will likely discourage utilities from participating in wholesale markets if the states lack data with which to assess the costs and benefits of that participation.
2. The states determine whether utilities join RTOs. The meaning of "RTO" has evolved, at least in PJM and Midwest ISO, to mean not only a regional transmission manager, but also a maker of regional markets. Given this evolution, a state commission will hesitate to declare the transfer consistent with

the public interest if the state cannot assure itself that the wholesale markets are or will be competitive.

3. Between the two poles of participation and nonparticipation in wholesale markets is a range of possibilities, all within the discretion of the state commission. In exercising that discretion, the state commission will consider the extent to which it can reduce the risks and increase the benefits associated with its exposure to wholesale markets. Data access will play a role.

#### **IV. Should state commissions be able to discuss confidential data among themselves?**

- A. FERC has stated that "the revised proposal should delete the Midwest ISO's proposal to permit Authorized Requestors to disclose Confidential Information to other Authorized Requestors." MISO August 6 Order at para. 562.
  1. The Commission there stated that permitting Authorized Requestors to exchange confidential data "severely limits Midwest ISO's ability to assess whether a party that receives the data has a legitimate need for it and whether the Authorized Requestor can keep the data confidential under their individual statutory and regulatory authority." Id.
  2. The Commission also stated that Midwest ISO and its stakeholders should consider whether market participants should be notified before MISO or the IMM "divulges" Confidential Information to state regulatory commissions. Id.
- B. Is there a legal or factual basis for this finding? MISO, the public utility who proposed the data-sharing provision, had expressed no concern about:
  1. its ability to assess whether a party that receives the data has a legitimate need for it
  2. whether the Authorized Requestor can keep the data confidential
  3. whether the exchange of information among Authorized Requestors would deprive market participants of information about the status of requests for information.
- C. Consider also these possible benefits of inter-state data sharing:

1. Obviating state investigations into events whose causes are explainable by the data: When adverse market events occur, data access, followed by internal state discussions, can resolve questions before investigations take on a life of their own. Allowing controlled and limited discussion of confidential data among state regulators would avoid forcing such concerns into a more formal template prematurely or unnecessarily.
2. Harmonizing state resource requirements: The MISOs TEMT, as amended per the Commission's November 8 rehearing Order at para. 326, notes at section 68.1.2.a that
3. "Market Participants that serve load within the Transmission Provider Region must comply with all applicable regulations and laws regarding reliability, including any reserve margin requirements, of the states in which the Transmission Provider operates."
4. Similarly, the TEMT, as amended per the November 8 rehearing Order at para. 327, provides at section 68.1.2.b as follows:
5. "To the extent that a Market Participant serves load in two (2) or more states in the Transmission Provider Region, the Market Participant must comply with the applicable reliability or resource adequacy requirements of each state in which it serves load."
6. Regional infrastructure planning is assisted by consistency across state plans. That consistency will emerge more reliably, and efficiently, if states can create working groups of Authorized Requestors to share and discuss information related to the various state reliability and resource adequacy requirements.

**V. Differences between the Midwest ISO plan and the PJM plan will not necessarily render a MISO plan unlawful**

- A. The Commission rejected the MISO's March 31, 2004 proposal in part because it varied from the PJM approach. August 6 rehearing Order at 557, 561-562; November 8 rehearing Order at 482 (stating that it will become "increasingly important" for PJM and Midwest ISO to have a common means of sharing data with state commissions).
- B. Do inter-RTO differences, by themselves, make a proposal unjust and unreasonable? If the Commission means that the datasharing regimes in the two RTOs must be

"identical," it would be imposing on data sharing a standard that is not satisfied by any other aspect of the two RTOs. Little about the two RTOs is identical. "Compatible" would be a better standard: can generators readily comply with both standards?