

SPARK

The on-line gateway for readers of Public Utilities Fortnightly magazine.



We Keep You a Step Ahead

Last month, in the January issue of our parent publication, *Public Utilities Fortnightly*, we took a little extra time and space to go into the nitty gritty details of American Electric Power's landmark bid to join the PJM grid group and—guess what? We think we touched a nerve. Readers appeared pleased that they had a place to turn to go beyond the daily headlines, to read and understand the real story.

So, when the case took a different twist in January and early February, emphasizing power prices, consumer savings and real-world dollars, we took the opportunity to update our story.

Bruce W. Radford, Publisher

BY THE NUMBERS

It's Down to Dollars For AEP and PJM

By BRUCE W. RADFORD

A funny thing happened on the way to the courthouse. What began as a policy fight between feds and the states has become a war over numbers — a simple counting up of dollars.

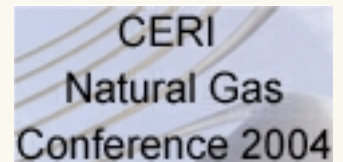
The case involves American Electric Power and the PJM grid. Early predictions had it running all the way to the U.S. Supreme Court, where the nine justices would resolve the impasse over the future of the nation's electric transmission network.

Instead, what we have now is an outpouring of highly technical cost-benefit studies, showing who would save how many dollars if AEP were to join the PJM RTO (whether that means full participation in bid-based markets, or just by transferring control over physical grid operations). Either way, the numbers are in. And the savings are substantial and compelling, but also asymmetric.

So in the final analysis, regardless of the law and theory, regulators may well find it difficult to deny PJM membership to AEP. The studies don't cross every "t" or dot every "i". In reality they are like apples and oranges; they pass each other like ships in the night. But they do shed some light on the matter. And in so doing, they promise millions of dollars in gains for huge swaths of consumers across the Midwest and Mid-Atlantic. How can regulators turn that down in good conscience?

This case was to be the ultimate reckoning for electric deregulation as an economic and legal theory. Does the Federal Power Act give complete control over electric transmission »

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to the federal government? Can the feds impose their will on the state public utility commissions (PUCs)? Can FERC force utilities to join regional transmission organizations (RTOs), with all the trappings of the standard market design (SMD), including bid-based markets, locational marginal pricing (LMP), and financial transmission rights (FTRs)?

Searching through piles of dusty law books, the Federal Energy Regulatory Commission had hit what it thought was a home run. In an obscure corner of PURPA, a 1970s-era law born of OPEC oil embargos and sweater-clad politicians, FERC had found a federal statutory provision that seemed to let it run roughshod over disapproving state regulators — all in the name of interstate markets and regional economic efficiency. (*See, New PJM Companies (preliminary order), Docket No. ER03-262, Nov. 25, 2003, 105 FERC ¶61,251.*) It just needed the Supreme Court to affirm the idea. Does Sec. 205 of the Public Utility Regulatory Policies Act allow FERC to “exempt” utilities from having to honor boycotts by state PUCs, and instead allow them (the utilities) to jump ship and join the federally sanctioned interstate grid groups that the States so adamantly abhor?

Naturally, the States have fought back. Their arguments are quite logical: How can the feds deny the right to PUCs to review matters that obviously rest within their jurisdiction? Yet now, quite simply, none of that may matter very much — especially if PJM and AEP can get out the word that millions of dollars are lying on the table, waiting for consumers to scoop up. In fact, a half-dozen states have already conceded the battle and now urge FERC to

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“The generation mix in PJM and in the Midwest are quite different ... the ability to import more coal energy into PJM and displace gas energy can be quite valuable.”

— *Michael Schnitzer, Northbridge Group*

“do the math,” go with the numbers, and allow AEP to join PJM.

But the most telling fact may be this: The very states that oppose FERC's preliminary finding (forcing AEP to join PJM as a full-fledged member) could choose instead, if they wanted, to sup-

port a simple compromise position offered by AEP. That compromise would allow AEP to join PJM without having to participate in bid-based markets, LMP, FTRs and other SMD reforms that many find objectionable. But for AEP that compromise would still capture the lion's share of the cost savings that arise from creating a giant, seamless regional market. Those savings would come from the basic notion of voluntary and cooperative power pooling—a concept that the electric industry has supported for decades and which clearly comports with the traditional, rate-base-style utility regulation that the state PUCs continue to endorse.

But the states that oppose FERC have not agreed even to this modest concession. They continue to cite SMD as the reason for their opposition, yet they refuse to accept the very compromise that would remove SMD from the equation while retaining millions in savings.

Why is that? To discover the answer, let's look at the numbers.

The Cost-Benefit Studies

As of the middle of this month, at least four major cost-benefit studies had been submitted to the record at the FERC **»**

FORTNIGHTLY'S

SPARK

Public Utilities Reports, Inc.
8229 Boone Blvd., Suite 400
Vienna, VA 22182
Phone: 703-847-7720
800-368-5001
Fax: 703-847-0683
<http://www.pur.com>

Bruce Radford, Publisher
radford@pur.com
Lori A. Burkhardt, Editor
lab@pur.com
Alex Stephen, Designer
astephen@pur.com

E-mailed mid-month to all *Fortnightly* subscribers.
Call: 800-368-5001

For e-mail address changes or other information, contact jclark@pur.com or 800-368-5001.

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in the case for AEP membership in PJM. Each study, prepared and submitted by different parties and consulting firms, tends to focus on different revenue and cost factors, and shows somewhat different results—though all appear to predict positive savings.

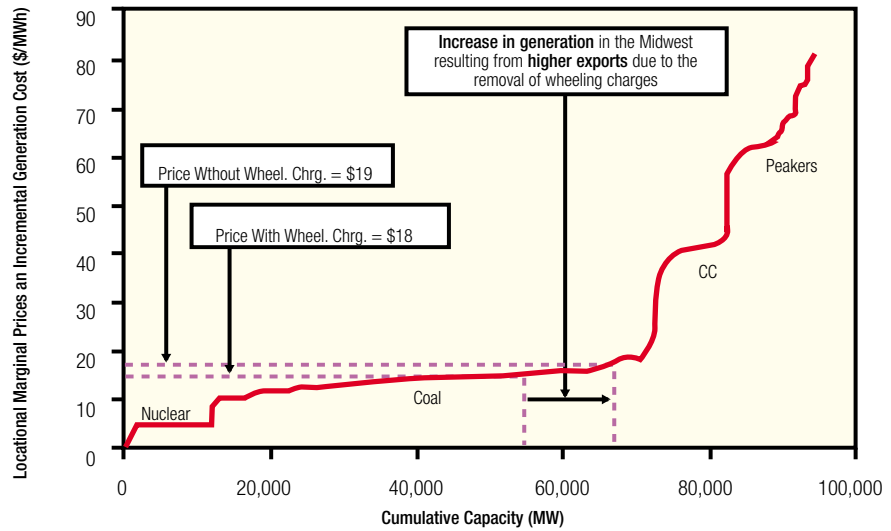
Understand also that the studies pinpoint at least four or five major categories of cost savings, which tend to benefit many different groups of beneficiaries—some at the expense of others.

For example, consider just some of the various groups of beneficiaries and potential opportunities for windfalls:

- AEP itself (as a regional, multi-utility holding company system now able to earn more revenues from off-system sales);
- Individual utility subsidiaries of AEO, such as Kentucky Power and Appalachian Power (which would see a change in costs required to serve their native loads, and would also receive load-weighted, allocated shares of AEP's increased off-system sales);
- PJM market participants (who pay for congestion and would see changes in their uplift costs);
- PJM's current members (who pay the RTO's administrative support costs and would seek AEP now picking up a share of that burden); and
- Plain old energy consumers (who would have an interest in how AEP membership in PJM might affect the the going price of wholesale power in their region, and the final delivered cost of power where they live).

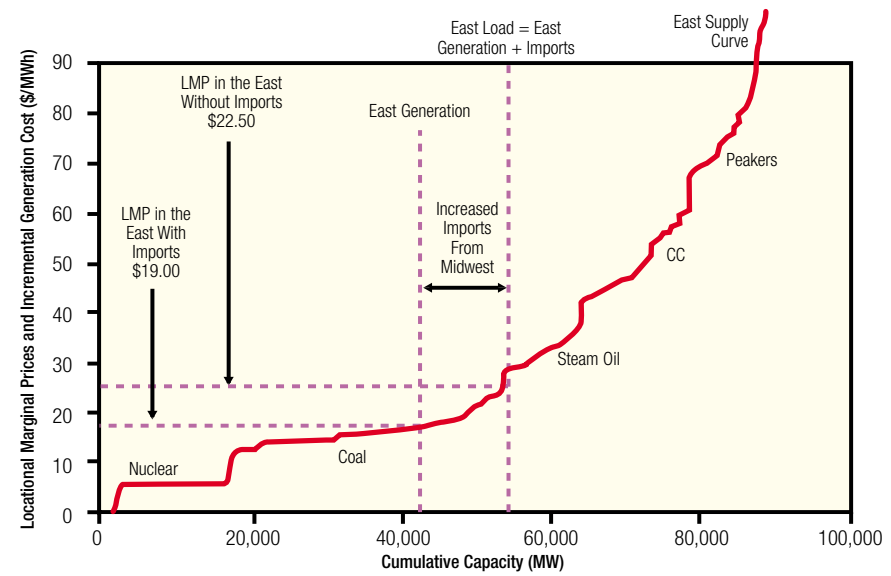
Nevertheless, despite this complicated picture, one simple fact stands out: most potential savings from AEP joining PJM appear to come not so much from the technical performance of PJM's market structures (bid-based dispatch, day-ahead market, LMP, FTRs, and so forth), but from opening the doors to allow the export of greater volumes of cheaper coal-fired power from the Midwest to the Mid-Atlantic.

FIGURE 2 ELIMINATION OF WHEELING RATES RESULTS IN INCREASED GENERATION IN THE MIDWEST



Source: Cambridge Energy Research Associates.

FIGURE 5 ELIMINATION OF WHEELING RATES RESULTS IN REDUCED PRICES IN THE EAST



Source: Cambridge Energy Research Associates.

**CHANGE IN WHOLESALE ENERGY COSTS
IF ALL PARTICIPANTS PAY LMPs**
(2002 \$millions)

Region	2004	2006	2008
PJM	(162)	(114)	(106)
Va.Pwr.	(83)	(82)	(82)

Source: Cambridge Energy Research Associates

And in large part, FERC has already opened those doors, by forcing the elimination of “pancaking” transmission tariffs, such as: (A) regional “through and out” rates (RTORs) on

inter-regional transactions, imposed by PJM the Midwest Independent System Operator (MISO); and (B) utility-specific T&O rates imposed by AEP and other utility systems on those same transactions.

This point is crucial. That so many benefits come from simple power pooling (albeit on a very large scale) tends to undermine FERC's argument that AEP must participate in all of PJM's market protocols. It tends to favor AEP's opposing claim that it ought not submit >>

to day-ahead markets and a bid-based dispatch, but need only grant control over its transmission system to an RTO, as the company has offered to do through its "PJM Lite" compromise position. That compromise would see AEP conforming to the original idea for an RTO, as envisioned by FERC's Order 2000, issued before the SMD took shape. After all, Order 2000 was state-of-the-art back when AEP had agreed to join an RTO as a condition of gaining approval for its merger with Central & South West, down in Texas. AEP continues to argue in theory that its merger authority promises nothing more than a 2000-vintage RTO, but adds that it favors a solution worked out through dialogue and compromise between the Feds and affected states, rather than a top-down mandate.

What follows is a rough overview of the principal cost-benefit studies presented in the case.

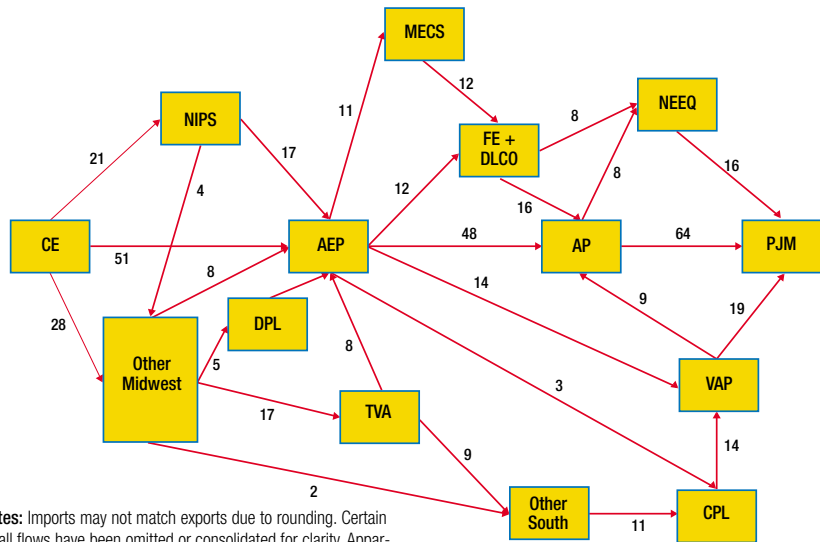
Study No. 1

Sponsor: American Electric Power
Author: Cambridge Energy Research Associates
Software: GE-MAPS (General Electric Multi-Area Production Simulation™)
Forum: Filed Jan. 20, 2004, at Va. State Corp. Comm'n (Case No. PUE-2000-00550); Filed Dec. 23, 2003, at Ky. Pub. Serv. Comm'n (Case No. 2002-00475)
Key Testimony: J. Craig Baker (for AEP), Hoff Stauffer (for CERA)
Summary: (5-yr. total nominal benefits, yrs. 2004-08, net of RTO admin. costs)

- **Full Compliance:** Full integration of AEP into PJM, according to FERC's wishes, saves \$188 million for AEP company-wide, \$56.7 million for Appalachian Power only, and \$13.4 million for Kentucky Power only, after taking account of administrative costs paid to PJM for RTO membership and market participation, versus a business-as-usual scenario (whereby AEP does not join PJM, and continues as a stand-alone control area with stand-

EXHIBIT 53

ComEd to PJM: 100 MW TRANSACTION, MODELED POWERFLOWS



Notes: Imports may not match exports due to rounding. Certain small flows have been omitted or consolidated for clarity. Apparently erroneous flows from VAP to NEEQ have been routed to PJM.

Source: Prepared Testimony of Stephen Henderson, filed Jan. 7, 2004, FERC Docket No. ER03-262.

alone dispatch.)

- **Compromise Offer:** Partial integration ("PJM Lite", with AEP joining PJM but not participating in market structures), saves \$283 million for AEP company-wide, \$84.7 million for Appalachian Power only, versus the business-as-usual scenario.
- **Rationale:** AEP's Baker testifies that most savings come from elimination of "through-and-out" wheeling charges, making it more economical for AEP to export cheaper coal-fired power to the East, and allowing AEP to earn a substantial increase in revenues from off-system wholesales.

Study No. 2

Sponsor: Cinergy
Author: Tabors Caramanis & Assoc.
Software: GE-MAPS™
Forum: Filed Jan. 7, 2004, at FERC (Docket No. ER03-262)
Key Testimony: Richard Tabors (for Tabors Caramanis)
Summary: (Annual benefits, reduced wholesale power costs, yr. 2005)

- **Broad International Region:**

\$214 million total consumer benefit (in year 2005) from full integration of AEP into PJM, representing reduction of 0.4% in wholesale costs to serve load, as measured across a broad combined region covering PJM, PJM West, New York, New England and New Brunswick, Ontario, AEP East, Dayton Power & Light (DPL), remaining areas of ECAR (East Central Area Reliability Council), and VACAR (Virginia and Carolinas areas of Southeast Area Reliability Council).

- **Sub-Regions:** AEP—\$41.7M, 1.3% reduction. DPL—\$3.7 M, 0.7%. Rest of ECAR—\$95.5 M, 0.9%. VACAR (outside of Va. Pwr.)—\$32.8 M, 0.3%. Virginia & Kentucky outside of AEP—\$19M.
- **AEP Subsidiaries:** Big Rivers—\$0.3M, 0.1%. East Ky. Pwr.—\$4.4M, 1.4%. Ky. Utils.—\$6.7M, 1.2%. LG&E—\$4.3M, 1.3%. Old Dominion—\$0.5M, 0.2%. Va. Pwr—\$3.7M, 0.1%.
- **Rationale:** Study measures efficiency benefits in terms of load-weighted average cost of >>

energy delivered hour by hour to each bus in study area. Savings come largely from correction of observed price “distortions” in LMP’s throughout PJM region, through more efficient dispatch and congestion management, by replacing incidents of TLRs (transmission loading relief) with a security-constrained dispatch with congestion costs paid through uplift charges that reflect the relative economic value of transactions.

Study No. 3

Sponsor: Exelon

Author: Charles River Associates

Software: Powerflow data from NERC (North American Elec. Reliab. Council)

Forum: Filed Jan. 7, 2004, at FERC (Docket No. ER03-262)

Key Testimony: Stephen Henderson (CRA), Michael Schnitzer (Northbridge Group)

Summary: An empirical study of recent TLR events involving AEP & PJM. Compares TLR costs to hypothetical redispatch across the combined AEP/PJM region. (The study quantifies savings from bid-based and market-based redispatch using LMP and FTRs, with particular emphasis on how power flows from Commonwealth Edison Co. (ComEd.) in Illinois, to PJM in the Mid-Atlantic.)

- **Cost of Congestion:** The study cites an average observed cost of roughly \$9.30 per MW for achieving congestion relief across AEP/PJM interface using LMP, FTRs, and PJM market structures, vs. \$77.86 per MW for relieving such congestion using the system of TLRs and physical curtailments currently in place.
- **Curtailed Transactions:** The study also documents that the seam between PJM and AEP represents 42% of TLRs (119 of 286) called by PJM in 2003, with 62% (673,000 MWhs out of 1.091 million MWhs)

“The notion that PURPA should be read as frozen in time, able to accommodate only the sort of pooling arrangements that happened to exist prior to enactment, is simply unreasonable.”

— *Former Congressman Phil Sharp, testifying on legislative intent.*

of curtailed transactions.

- **Rationale:** Observes that, on average a curtailed transaction (relying on TLRs instead of PJM market structures) tends to provide only about one MW of congestion relief for each 10 MWs of transaction curtailment, because of the dynamics of power flows across a networked transmission grid. The effect is multiplied by the fact that TLRs mandate curtailments of transactions according to physical characteristics, without reference to the economic value of the transaction or the production cost profile of the curtailed generating plant.

Study No. 4

Sponsor: PJM RTO

Author: PJM RTO

Software: GE-MAPS™

Forum: Filed Jan. 7, 2004, at FERC (Docket No. ER03-262)

Key Testimony: Andrew L. Ott, Richard A. Wodyka (for PJM)

Summary: (Annual benefits, reduced annual power prod. costs, yr. 2005)

- **Greater PJM Region:** Roughly \$300 million in total production cost savings in year 2005 from full integration of AEP into PJM, as measured across a region covering PJM, PJM West, AEP East, DPL, and ComEd. An additional \$110M of production cost savings if Va. Pwr. joins PJM.
- **Offsetting Admin. Costs:** PJM incurs \$63M of capitalized project

costs, to be depreciated over three years, to integrate new members (AEP, DPL, ComEd, Va. Pwr.). PJM also to incur \$95M in incremental annual operating costs, and must reallocate some \$35M in “pre-integration” expenses heretofore allocated to AEP and other prospective new members. PJM estimates reduction of total administrative costs for each RTO member, \$0.54/MWh to \$0.43/MWh, by spreading costs among larger membership.

- **Rationale:** Same basic explanation as Study No. 2. PJM adds that generator availability has improved across the PJM region, from 81.4% in 1994 to 86.3% in 2002—attributed to efficiencies from LMP, bid-based markets, and security-constrained dispatch.

Where the Savings Lie

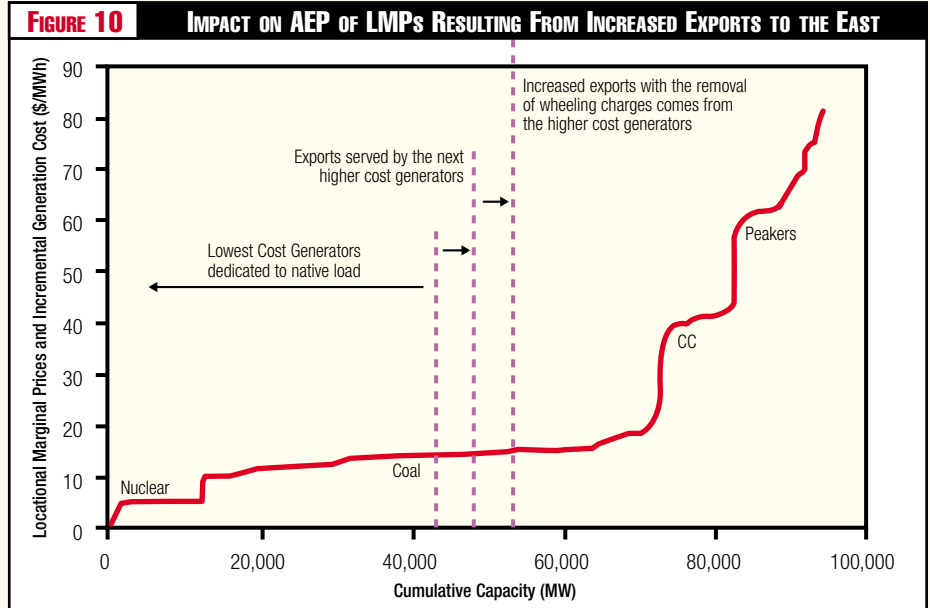
In its preliminary order of Nov. 25, FERC had touted the superior efficiency of PJM’s market design (a more economic utilization of resources, in the words of PURPA), as reason to compel AEP to join PJM as a full-fledged member, and as reason to grant an exemption to AEP from contrary orders from the Kentucky and Virginia PUCs, that otherwise would have forced a delay, or perhaps prevented membership altogether. The idea was that consumers would enjoy savings in the delivered cost of power, stemming from efficiencies in dispatch of power plants and management of grid »

congestion, by leaving those functions to competitive bid.

These efficiencies would occur in theory through PJM's bid-based day-ahead unit commitment and subsequent real-time dispatch keyed to locational prices set by those day-ahead bids. Competing transactions also must "buy through" the congestion, covering the net cost of financial grid rights, to weed out the less economical transactions. By contrast, the congestion management system otherwise in place to rationalize seams between AEP and PJM would curtail any and all transactions exceeding the physical limits of the system after attempts at a physical redispatch, thereby "protecting" certain transactions already scheduled and grandfathered, even if economically inefficient.

Yet it seems that the real savings stem from the underlying geographic, technological and physical characteristics of the nation's installed fleet of power plants. In short, there's a lot of available and cheap coal-fired power out in the Midwest—in Ohio and beyond—that's itching to push East and invade PJM and the Mid-Atlantic states, where higher-priced gas-fired power calls the tune. This pressure wave of cheaper power imports creates a sort of basis differential between East and West, just as occurs between producing and consuming areas on interstate natural gas pipelines. As explained in testimony presented by Michael Schnitzer, a key witness for Exelon, this pressure wave is revealed by a marked difference between hourly LMP readouts for the PJM western hub, and at the PJM/AEP interface:

"The generation mix in PJM and in the Midwest are quite different," Schnitzer explains. "The Midwest has a greater proportion of baseload nuclear and coal capacity, such that gas-fired generation sets the market price in a relatively few hours per year. In all other hours, there is surplus nuclear and coal energy available for sale outside the region."



Source: Cambridge Energy Research Associates.

By contrast, he adds, PJM has a very different generation mix: "In PJM, gas and oil generation sets the market price in most of the on-peak hours. At gas prices of \$5 per MMBtu, yielding gas-fired electric prices of roughly \$40 per MWh, there is a large incentive to transfer power from west to east whenever gas is on the margin in PJM and coal is on the margin in the West.

"During 2003," Schnitzer adds, "a positive spread of \$10 per MWh or more was observed for approximately 1500 hours, or 17 percent of the year."

Yet, without more, these savings would remain untapped, because of the prohibitive cost of transmission—a cost imposed in part by physical constraints:

"These hours are mostly on-peak hours, and represent periods when coal-based energy was available to the west of PJM to displace gas or oil generation within PJM, but transmission constraints limited the amount of the feasible transfer."

Of course, what Schnitzer does not mention is that much of the infeasibility of transfer stems from artificial factors, in the form of pancaked wheeling charges. Now, however, with FERC

having eliminated pancaked wheeling charges for power movements between MISO and PJM, and between AEP and PJM, the floodgates are opened. The savings pour in from Midwest to Mid-Atlantic, brought to market over AEP's substantial transmission network:

"During these hours," adds Schnitzer, when coal is on the margin out West, and gas on the margin back East, "the ability to import more coal energy into PJM and displace gas energy can be quite valuable \$20/MWh or more."

This pressure wave of coal-fired power moving from west to east can be seen in Figures 2, 5, and 10, reproduced here and numbered as they appeared originally in the Exelon cost-benefit study introduced by Stephen Henderson, of Charles River Associates. The consumer benefits appear driven primarily to the particular embedded geographic location of power plants. Yet even so, Schnitzer is able to show that at least some of the consumer cost savings do come from the more efficient, PJM-style of dispatch and congestion management, as FERC has insisted:

"So in these hours in particular, an uneconomic level (Continued on p. 13)

INTERVIEWS

Meet the Commissioners

BY LORI A. BURKHART

There are two new commissioners at the Federal Energy Regulatory Commission (FERC), who will be helping set energy policy for years to come. After surviving time-consuming nomination battles on Capitol Hill, the FERC welcomed Suede G. Kelly and Joseph T. Kelliher in December 2003.

Both commissioners are attorneys and have extensive energy backgrounds. Kelly hails from New Mexico, and has held a wide range of positions, from counsel to the California Independent System Operator to chair of the New Mexico Public Service Commission. Kelliher served as majority counsel to the House Committee on Energy and Commerce and most recently was senior policy advisor to Secretary of Energy Spencer Abraham.

Fortnightly's Spark talked to the new commissioners to give our readers an opportunity to get to know them and where they stand on policy issues. They hold positions at FERC along with Chairman Pat Wood III and Nora Mead Brownell. Commissioner William Massey left the FERC after serving for ten years and now there is one open seat.

Suede Kelly



SPARK: You've only been serving at FERC for a short time, how has your experience been so far?

Suede Kelly: It has been an excellent experience. I am so impressed with FERC staff—the high level of professionalism, competence, knowledge and commitment. It already is a very

rewarding experience. I also have enjoyed working with the other commissioners; all three of them are public-interest minded and forthcoming about their concerns and their views. They are good people to work with.

SPARK: Are you fully staffed now and who are they?

SK: I have three technical staffers—Maria Vouras, Rahim Amerkail and Michael Krauthamer. In addition, Donna Glasgow is in charge of communications and Carrie Blocker is my secretary. I hired them all at FERC; they all previously worked in other offices here so they have good experience.

SPARK: You served as Chair of the New Mexico Public Service Commission, how does that experience shape your decision-making process at the federal level?

SK: It is wonderful to have had that experience because it does give one an understanding of the deliberative process and the collaborative process

involved in reaching a decision as a member of a commission. In many ways the process of making a decision as a FERC commissioner is very similar to that of making a decision as a state commissioner. The objectives are the same—just and reasonable rates, reliable service, and non-discrimination. The interests that are involved in the cases are the same. Of course in other ways it is different, because it is a different jurisdiction. But just like at the state level, at the federal level there are the other branches of the government that take an interest in the decisions and are involved in the laws, and here it is the Congress and the President.

SPARK: There is a geographic disparity in advancement of standard market design (SMD) and regional transmission organizations (RTOs); do you favor voluntary or mandatory SMD and RTO policies?

SK: Well when you look at the areas that don't have RTOs or ISOs now—that is primarily in the West—and in those areas the make-up of the participants in the electric transmission system are very very different from the make-up of those in the Eastern interconnect. Specifically in the Northwest, I believe it is 40 percent of the transmission lines—and I should check that number—are owned by non-jurisdictional entities. You have for example, Bonneville Power Administration. So as a practical matter, forming an RTO in most areas of the West just wouldn't work very well if the goal is to organize the wholesale market and make it work more efficiently, unless the non-jurisdictional entities participate. Since FERC doesn't even have jurisdiction over them and couldn't order them if FERC wanted to, I think that the best approach to RTO formation in those areas is a voluntary, cooperative effort.

SPARK: After the August 2003 blackouts, what do you believe is the best way to ensure grid reliability in the U.S.? »

SK: I think that the first thing FERC needs to do with respect to the blackouts is determine what lessons are to be learned from that blackout and to ensure that those lessons are learned by the industry. The Department of Energy anticipates putting out their final report on the blackout in March, and so we'll be waiting anxiously for that report. It appears from the preliminary report that much of the cause of that blackout had to do with operational failures as opposed to infrastructure failures. So assuming that the final report reiterates that, I think that it underscores the importance of mandatory reliability standards for operations. It appears there is a consensus in the industry, as well as in Congress, that we need mandatory reliability standards.

SPARK: Looking ahead, what issues are going to be at the top of FERC's agenda in 2004?

SK: Well there are going to be a lot of them. In the organized electric markets there are a couple of big ones. California is redesigning its market and so that is very significant. FERC just held a technical conference on that and it will be very important, not only to the people of California, but to the entire west, since the California market is an integral part of the western market. Also, having MISO work and work well is important.

In the un-organized markets, there has been some—particularly in the west—sub-regional cooperative planning sessions that have been taking place among transmission owners and other stakeholders to brainstorm and think about ways to make their wholesale markets work more efficiently. Obviously, everyone wants his or her markets to work better and the west is no exception. That is to a large extent outside the auspices of FERC, but as a westerner and as a recent addition to FERC, still having roots in the west, I have a special interest in that process and will do whatever I can do to foster

It appears there is a consensus in the industry, as well as in Congress, that we need mandatory reliability standards.

it. I think that sub-regional planning for the future is very important in the west and I think it is encouraging that stakeholders are beginning to pursue that.

Market manipulation is an important topic. FERC has staffed up its market monitoring operations and takes seriously its mandate to ensure that the markets that do exist work well, that there is as much transparency as possible, and that manipulation, fraud and abuse doesn't occur. So we will be looking to achieve that both in electricity and in gas. In electricity, in the organized markets, we will be looking at the functioning of the market monitoring units that are at the ISOs and RTOs and their responsibilities. How well they are able to carry them out given the processes that are in place, whether those processes need to be changed to ensure that market monitors have the appropriate authority and ability to determine if there are problems developing and how to respond to them.

A current issue is the appropriate market power test to determine which electric utilities should have market-based rates.

A current issue is the appropriate market power test to determine which electric utilities should have market-based rates. That will be a significant undertaking on the part of FERC.

Regarding gas, the fundamentals really say it all. Prices are high and supply is tight. So we are looking at gas prices to ensure that they are reflecting the fundamentals of the market and are not the product of any adverse influence. We have not seen that—I want to underscore that we have not seen that—but we are continuing to look at gas prices. Supplies appear to be adequate, but over the long-term supplies are going to be tight and so what FERC is seeing is quite a few applications for LNG facilities, and so that will be a big issue this year and next year.

In the hydro arena, the first hydro re-licensing case was filed the week before last (the week of Jan. 19) using the new integrated licensing process that FERC adopted in a rulemaking last summer. So I'll be following that to see if the process works the way FERC intended it to work.

SPARK: Are you finding that you have to recuse yourself from many cases?

SK: There are no cases pending before FERC that I was involved in. However, I represented FPL in building a wind farm in eastern New Mexico. FERC's recusal regulations specify that no commissioner may sit on any case in which, not only a former client, but all affiliates of a former client, are a party for one year since you last represented them. So any case in which any affiliate of FPL is involved I have to recuse myself until June. »

Joseph Kelliher



SPARK: You've only been serving at FERC for a short time, how has your experience been so far?

JK: I've really enjoyed it. I think the issues are very interesting and I'm very impressed with the FERC staff—the quality of the FERC staff is very high and the morale is very high.

SPARK: Are you fully staffed now and who are they?

JK: I have three attorney advisors. One is Len Tao and he works on electricity issues. Another is Niles Nichols, whose portfolio is gas, hydro and oil pipelines. I hired them in December, and I recently hired Larry Gasteiger from the solicitor's office. Cathy Tripodi, who handles communications came over with me from Department of Energy.

SPARK: You have served at the Department of Energy and on Capitol Hill, how has that experience shaped your decision-making process at FERC?

JK: I think it helps because from my former perspective, I have noticed that both in the Executive Branch, and in Congress as a staffer, and as someone who has worked on energy issues for awhile, a lot of the time in town there is

this notion that issues can be divided between legislative or policy issues. So Congress deals with legislation exclusively, and agencies deal with regulatory issues, and that there is no overlap—things can be neatly put into those two boxes—I just don't think that is true. I think if you look back at major energy policies, major policy questions tend to be addressed by Congress and FERC collaborating.

Open access policy is the clearest example, where it started with PURPA (Public Utility Regulatory Policies Act of 1978). PURPA promoted wholesale power competition, but it also did have open access provisions. People forget about those provisions since they proved to be unworkable ultimately and no one ever got a wheeling order under those provisions. But there was an open access provision, and then FERC developed its open access policies that it started imposing on a utility-by-utility basis through merger applications and market-based rate applications. Then Congress adopted the wheeling provisions in the Energy Policy Act and FERC issued Order 888 afterwards, so there was collaboration between FERC and Congress on open access policy. So that notion that there is a neat divide between what Congress does and what FERC does, I just don't think is true. I think when FERC acts in a policy-making role, that for practical reasons it has to work with Congress. And it has to work with the states. The electricity regulatory scheme in this country is much more of a federalist approach than our gas policy. In gas regulation, FERC has the predominant role and the state role is extremely modest. In the electricity context, the state role is much more important, so as a practical matter FERC has to work closely with the states, with Congress and the Executive Branch on major policy questions.

SPARK: There is a geographic disparity in advancement of standard market design (SMD) and regional transmission organizations (RTOs); do you

favor voluntary or mandatory SMD and RTO policies?

JK: I start from the recognition that for the near-term, at least, we will have both organized markets and bi-lateral markets. I don't think that every region in the country is going to adopt an RTO in the near future. I think one challenge to FERC is that it has a general duty to prevent unjust and unreasonable rates and to promote effective competition in regional power markets. Those regional power markets have different structures—there are differences even among those regional markets and what their market designs and rules are. There certainly are differences between the organized markets—if you were to collect them all—and the bilateral markets. So I think FERC has to develop policies that work in both types of power markets.

SPARK: After the August 2003 blackouts, what do you believe is the best way to ensure grid reliability in the U.S.?

JK: Well I think you do need to have enforceable reliability standards. That is clear, and violation of the current voluntary standards did contribute not just to the August 2003 blackouts, but also the July 1996 and August 1996 blackouts. So the last three major blackouts in this country, in terms of regional grid-related blackouts, not distribution system failures, all were caused in part by violation of voluntary reliability standards. So I think you need to have enforcement of reliability standards. But you also do need to have a stronger grid, we need to have greater investment in the transmission system. FERC was briefed on the state-of-the-markets report at the last public meeting (Jan. 22). At that briefing we were told the transmission grid has expanded 0.5 percent in the past four years. So that is fairly stagnant, close to non-existent, but stagnant at least, and that plays a role in grid reliability as well. A stronger grid would be more reliable. So I think the commission does >>

have a duty to promote investment in the transmission system.

SPARK: Looking ahead, what issues are going to be at the top of FERC's agenda in 2004?

JK: In hydro, the major initiative will be implementation of the hydro licensing reform rule. That rule has been finalized, so now it is a question of implementation.

In the gas area there are a number of gas issues that I think are interesting—and I admittedly have a lot to learn on the gas side—but the gas quality conference the FERC is holding Feb. 18 could lead to some action by the commission. I have only been here a short time but there have been a number of orders that dealt with gas quality issues. The commission is deciding whether or not it should take some generic approach. One reason FERC is holding the conference is the recognition that we are going to be relying more heavily on liquefied natural gas (LNG). Even if there were no gas quality issue under the *status quo*, and there probably is, it will be introduced by greater reliance on LNG because of some physical differences.

Also, FERC has dedicated a lot of resources to LNG applications and I think FERC should be commended on the policy it developed in the *Hackberry* case. But that is more of a question of implementing new policy and dedicating resources to acting on applications. I think the chairman has placed a high priority and dedicated a lot of resources to that.

Another issue on the gas side is the gathering line issue, what should the standard be for determining the jurisdictional split between gathering and transportation facilities, particularly in the Gulf. That is something FERC placed an important amount of attention on over the past two years. That is something important to the chairman and something FERC will address.

An interesting gas issue concerns storage. The commission has had policies on gas storage with respect to mar-

What should the standard be for determining the jurisdictional split between gathering and transportation facilities, particularly in the Gulf?

ket-based pricing that have resulted in a good number of facilities receiving market-based pricing in the production areas, but not very many in the market areas where arguably there is more need for gas storage. The commission has publicly discussed whether we should revise our market-based rate policy to encourage more gas storage capacity in the market areas, and I certainly support asking that question and developing some facts.

In electricity we are looking at market power. The commission held the supply margin assessment (SMA) technical conference in January and last week (first week in Feb.) held the conference on local market power mitigation. For SMA the commission does need to make some decisions. We have announced this interim approach towards generation market power, that effectively has been suspended for over two years, and a number of utilities—over 70—have failed the new interim test. The FERC has to do one of two things. It either has to enforce that test and impose mitigation on utilities that fail it, or it needs to reform or replace the test. To me that was the big question at the technical conference last month—which path do we go down? Keep the current test and enforce it, or revise it?

With respect to local market power mitigation and last week's technical conference, one question was: should we have a generic approach towards local market power mitigation in the organized markets? I think most people said no you shouldn't. If that ends up being the commission's view, then the question is: Well where you find there is local market power mitigation

that is going to exist for some significant period of time, what kind of range of options or policies should be available to mitigate it?

Another policy the commission is looking at concerns market manipulation. The commission issued its market behavior rule in November and there have been a number of rehearing requests, so the commission will probably have to act on a rehearing order at some point. I think the commission should proscribe certain forms of behavior and I think the commission has the legal authority to do so by finding that they are inherently unjust and unreasonable. But we need to finalize that.

The commission will continue to develop its RTO agenda. I don't think every region is going to adopt an RTO and the challenge for us is to develop policies that work in both the bi-lateral and organized markets.

SPARK: Are you finding that you have to recuse yourself from many cases?

JK: I have asked our designated agency ethics official that question and so far I have not had to recuse myself. That is perhaps an advantage from having had such a long nomination process—whatever relationship I have had with people is in the distant past. My only recusal is with respect to the Department of Energy. Where the DOE is a party I don't necessarily have to recuse myself, but I have to ask whether I need to recuse myself. That generally only would occur in Power Marketing Administration (PMA) cases, but I do ask that question when there is a need to. ■

FEATURE

Competitive Retail Markets Pass The 50,000-MW Mark

BY LORI A. BURKHART

Retail power competition in the U.S. experienced substantial progress in 2003, reaching a milestone of over 52,000 MW of peak electric demand being competitively served. That represents an increase of 12,000 MW in just the last twelve months according to a recent study by KEMA. The 52,000-MW represents seven percent of the approximately 720,000 MW of total U.S. peak summer demand.

The over 200-page study itself is proprietary to members of the Alliance for Retail Choice, a group of national retail energy suppliers. But Julie Blunden, executive director of the Alliance told *Spark* why the study is important. She notes that, "even if you are an electricity insider and are familiar with what a thousand MWs looks like, the fact that we have hit 50,000 MW often is not fully understood within its context." Blunden adds that number is larger than the entire wholesale electricity markets in New England, New York and California. The implications:

- The competitive market is quite sustainable—it is not a situation where the retail market can be extinguished because a single state commission decides to roll back or suspend—as in the case of California; and
- The pace at which the market is expanding is expected to continue on the same order of magnitude in 2004, because of changes in the Texas market and several other markets where changes already are scheduled.



"I don't foresee anything other than market expansion from among our members."

—Julie Blunden, Alliance for Retail Choice

But the competitive retail market still favors the larger commercial and industrial (C&I) customer over the residential customer. "Competition in power markets, primarily for large

buyers, continues its rapid advance," asserts Taff Tschamler, director of KEMA's Retail Energy Markets advisory service, and one of the architects of the report. In fact, the residential market represents only ten percent of the 52,000 MW. Blunden points out the residential markets where there are the most substantial penetration rates are Texas and Ohio respectively. She says that based on the six years of retail restructuring history, that residential customers given a choice and given a market design that support their choices, actually are happy to go shopping for electricity just as they have shopped for long-distance service. But Blunden adds there aren't very many examples of markets that are designed in such a way that supports their choices, and that Texas is really the best example. "In Ohio the numbers are really due to a huge aggregation movement," she explains. "There you have chunks of customers, usually municipalities, making this decision to go shop on behalf of their customers and then giving their customers the choice not to participate if they don't want to."

But the Alliance wants regulators and states with open retail markets to be aware of both the size and the expansiveness of the retail markets. "It is easy to understand that Texas is the leader among the retail markets and it is worth looking to Texas," Blunden says, but "on the other hand we want them to pay attention to the fact that the retail markets are dispersed enough across a wide number of states such that the regulator becomes interested in what is happening in several states from a fundamental retail market perspective." She stresses that the opportunity now exists "to look at a bunch of different petri dishes at this point and see what is working in different places and why, and we don't think that there is a single model that works in every single state." And while each state operates under its own sets of constraints, Blunden believes there is a lot to be learned from a few of the key ►►

states with regard to fundamental competitive design. She gives the example of default service design as being something all regulators would benefit from learning about with regard to places that have had the most success recently. She points to California, Ohio, Illinois, New York and Pennsylvania—the five states over the 3,000-MW threshold of competitive retail power. “Texas, interestingly, while it does dominate is not the majority of the MW,” she explains. “There are some states with substantial competition and another rung of states beneath that, some of which have substantial competitive penetration; they just are not very big states. So even if you have a substantial number of industrial customers who have switched, on a percentage basis, the total MW number doesn’t hit the 3,000-MW threshold.”

But are the competitive suppliers making money? “Although some individual firms continue to struggle,”

lamented Tschamler, “the overall financial health of competitive providers has unquestionably improved over the past two years as the scale and scope of these organizations increases and they gain experience and build infrastructure to profitably compete for customers.” In fact, there is an increase in the number and market share by new entrants. KEMA notes that over the past year, more than 20 firms have entered the competitive retail power markets, while the top five competitive providers now serve between 2,500 to 10,000 MW of customer peak demand, equivalent to a mid- to large-sized utility.

Blunden points to two member companies that are national in nature when serving large commercial customers—Constellation NewEnergy and Strategic Energy. “In addition what you will see is either companies that are regionally born or regionally focused that are considering national

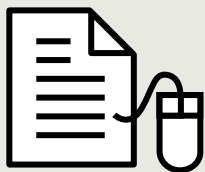
expansions—a good example of that among our members is Reliant Energy,” she explains. The Alliance for Retail Choice members also includes Centrica/Direct Energy and Green Mountain Energy. And they all intend to grow. Blunden says, “I don’t foresee anything other than market expansion from among our members, in fact, I generally hear that their challenge is to choose from among the markets that are open concerning which one to enter next.”

In sum, the Alliance wants to change the mindset of the retail market in general having been negatively affected by the perceptions related to the wholesale market decline over the last several years. “Even though all of my members are working every day in most of these open states to improve and evolve the market design rules, but when you cut to the chase, it is working really well and we have a market that is thriving,” Blunden concludes. ■

Tell Us About It

Fortnightly's Spark is interested in hearing from you. We want to know what you think about prevailing issues that may or may not be mentioned in this issue. Be advised *Spark* may publish your thoughts. To get things started, *Spark* noted that the Federal Energy Regulatory Commission’s proposed budget indicates it would pursue implementation of reliability rules.

Spark wants to know who do you believe should be in charge of reliability, the FERC, or the North American Electric Reliability Council (NERC)? Send your responses to radford@pur.com



BY THE NUMBERS

(Continued from p. 6)

of physical transmission service, relative to regional LMP markets, can be quite expensive. For example, 500 MW of foregone import capability under these circumstances could 'cost' \$10,000 per hour, or \$15 million if there were 1,500 hours per year where coal was available to displace gas. For 1,000 MW of foregone import capability, the cost could be twice as high, or \$30 million per year."

What FERC Must Decide

Utility regulators in Kentucky have agreed to meet by April 1 to rehear the application of AEP subsidiary Kentucky Power to join PJM, and to rule on that application by June 30. *See Ky.P.S.C. Case No. 2002-00475, Aug. 25, 2003 (order granting rehearing), and Jan. 5, 2004 (order setting procedural schedule.)*

And in Virginia, the State Corporation Commission has set a hearing for July 27 to decide the fate of the PJM application filed by AEP subsidiary Appalachian Power. Virginia law requires electric utilities to join an RTO by Jan. 1, 2005, but forbids any such move before July 1 of this year.

By contrast, according to its orders issued to date, FERC has set Oct. 1 of this year as the earliest possible date for AEP to fully integrate itself into PJM. Some have cited the difference in these dates in all seriousness as indicating that Kentucky and Virginia are not preventing AEP from restructuring any more than FERC has already done. In fact, when asked in the hearings whether AEP could join PJM "tomorrow" if FERC would issue a final order "today," the Exelon executive and former FERC chair Elizabeth Moler was heard to say, "Tomorrow, no. October 1st, 2004, yes."

So who's real the stick-in-the-mud?

From a purely technical standpoint, FERC must now weigh evidence and decide a collection of very precise questions, before it can assert PURPA Sec. 205 as reason to sidestep the wishes of

Kentucky and Virginia:

- Does AEP's commitment to join PJM qualify as "voluntary"?
- Would AEP's joining of PJM represent a "coordination" of electric utilities?
- Is the move aimed at obtaining "economical utilization" of facilities and resources?
- Are Kentucky and Virginia "preventing" AEP from joining PJM, by their own state laws or regulations?
- Are those same state laws or regulations designed to protect the public health, safety or welfare?
- Are those laws or regulations designed to protect the environment, or conserve energy, or mitigate the effects of fuel shortages?

If it can answer questions 1-3 as "yes," and answer questions 4-6 as "no," then FERC can use PURPA to bypass the wishes of state regulators in Kentucky and Virginia.

Generally, opponents claim that AEP's bid to join PJM cannot be "voluntary," since it agreed to join PJM only to win approval of its merger with Central & South West (CSW). Second, as claimed by Howard Spinner of the Va. SCC, and echoed by others, joining PJM does not qualify as "coordination," since the authors of PURPA had envisioned a traditional cooperative power pool for central dispatch, with a split-the-savings approach, whereas PJM's market system implies winners and losers, and turns utilities into "rivalrous competitors."

Spinner had argued artfully that "Congress contemplated the expansion or formation of then-existing power pooling arrangements—not competitive, bid-based arrangements such as are found in PJM today."

Spinner and others add that PJM's bid-based dispatch cannot be seen as "economic," as there is no assurance that the bids that clear the market (and thus the LMPs) will not sometimes exceed marginal costs.

The opponents continue that Kentucky and Virginia cannot really be »

Next Month's FORTNIGHTLY

Fortnightly magazine eyes the merchant generation fallout in March as it takes a look at the transfer of power plants to regulated utilities, and how those entities then are affected.

Here is a glimpse of what you'll find:

▶ Back to the Rate Base

In 2003, just over 1.4 GW of unregulated generating capacity was converted into rate-based assets. At least another 5.6 GW will be converted soon. What supply procurement practices are appropriate in today's power market?

▶ Pricing Power in Wholesale Markets: A Risky Business

The challenge of how pricing is applied can be the difference between success and a long-term decline. The trading model has many benefits, but application of that model makes all the difference.

▶ Risk-Based Pricing

Customers with greater risk require greater working capital set-asides to address anomalous or unexpected events. Risk-based pricing provides a structured approach to value the elements of retail supply cost risk and provide a systematic structure to incorporate these risks into prices.

▶ The Road Not Taken

Have regulators selected the wrong market design in their restructurings during the past two decades?

▶ Hardly Adequate

A pseudonymous executive explains why the CCRO's recommendations on capital adequacy don't pass muster.

▶ NERC's Cloudy Crystal Ball

NERC's forecasts for peak demand growth have consistently underestimated actual levels of growth. How does that affect projections for new construction?

seen as preventing AEP's move, since many other elements of the transfer to PJM remain unsettled, such as the finalization of SECA tariffs designed to recapture and allocate the transmission service revenues lost to AEP from termination of "through & out" rates, and the ironing out of a final "hold-harmless" agreement (pending in FERC Docket ER04-364) to protect utilities in Wisconsin and Upper Michigan from the unsettling effects of loop flows.

Finally, they assert that the jurisdictional concerns of Kentucky and Virginia display a nexus with the concept of "public welfare," since states retain jurisdiction over the siting of new transmission lines and the granting of certificates of convenience for their construction, and certainly ought to be able to bar the transfer of assets (local transmission networks) deemed essential to providing the bundled, monopoly distribution service mandated by state statutes.

In fact, Exelon went so far as to hunt down and depose Phil Sharp, a key congressman and congressional committee chairman from the late 1970s, who helped draft and pass PURPA. In his testimony, Sharp insisted that the legislators who voted for PURPA had not intended to limit the idea of "coordination" to cooperative power pools of the era, which would have excluded today's bid-based PJM system from eligibility:

"Mr. Spinner's notion that PURPA Section 205 should be read as frozen intime, able to accommodate only the sort of pooling arrangement that happened to exist prior to PURPA's enactment, is simply unreasonable."

Sharp adds that if protection of state regulatory regimes could qualify as protecting public welfare, then the exception (the protecting of state officials from rules bypassing by FERC) would swallow the rule (that FERC can "exempt" utilities from the effects of

According to Exelon and Charles River Associates, it should cost about \$9.30 per MW to relieve congestion across the AEP/PJM interface, using PJM's standard market design. But without an RTO, using TLRs and physical curtailments, it costs eight times more—about \$77.86 per MW.

certain state PUC actions.)

As PJM asserts in its post-trial brief, filed on February 12, "losing jurisdiction is not a health or safety matter."

Such arguments may address the issues at hand, but they sound like angels dancing on the head of a pin. How important is it, really, to determine for all time whether it is Kentucky, Virginia, or even FERC that has done more to "prevent" AEP from joining an RTO? Virginia could say it was Kentucky's fault. Kentucky could then just return the favor.

Elizabeth Moler, not entirely without bias, sees certain states as guilty of

pushing "revisionist history" on the FERC:

"If history is any guide," she argues, it is apparent that neither state has shown any inclination to grant the approvals ... Indeed, they have evidenced nothing but antipathy toward PJM, and this commission's Standard Market Design Initiative."

Uniting in favor of FERC, SMD, and PJM, a coalition of state regulators from Illinois, Indiana, New Jersey, Michigan, Pennsylvania, and the District of Columbia urge FERC to exempt AEP in no uncertain terms. They blanch at the thought of initiating a dialogue on AEP's "PJM Lite" compromise proposal—words that "inspire despondency," they say, "in all who have participated in the endless dialogues of the previous five year." (The Ohio PUC appears to be the only state regulatory agency willing to go on record to support AEP's compromise offer.)

But in all the thousands of pages of hearing transcripts and witness testimony, AEP's Craig Baker may have offered the most telling comment. And so when asked whether FERC would first need to see a cost-benefit analysis, showing net benefits, before ordering AEP to join PJM, Baker gave this ironic answer:

"No," he said. "Cost-benefit analyses are not useful in all situations, they cannot reasonably capture all of the considerations."

Yet I would venture that Baker got it wrong by exactly 180 degrees, and that he understood that fact full well, even as he spoke.

I would venture that Baker believes that his cost-benefit study is pretty darn persuasive, and that FERC's regulators will find it difficult to ignore all those dollars spread out on the table. ■

Bruce W. Radford is Editor in Chief of Public Utilities Fortnightly magazine.

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