UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Electricity Market Design and Structure Docket No. RM01-12-000

NOTICE OF EXTENSION OF TIME AND OPPORTUNITY TO SUBMIT COMMENTS ON REGIONAL TRANSMISSION ORGANIZATION ISSUES DISCUSSED AT WORKSHOPS

(October 30, 2001)

As noticed on September 28, 2001 and October 5, 2001, a series of workshops was held from October 15 through October 19, 2001 at the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426. The purpose of the workshops was to discuss core issues related to the development of efficient electric markets in an era in which electric transmission systems will be operated by Regional Transmission Organizations (RTOs).

The Commission's staff has developed summaries of the key issues discussed at each workshop and is attaching those summaries to this notice, as well as posting the summaries on the Commission's website at www.ferc.gov under "RTO activities" to encourage further discussion on the development of RTOs.[1] These summaries reflect what the staff heard, including any points of consensus among the panelists at the workshops. The summaries are not intended to suggest that there is an industry-wide consensus. The primary purpose of releasing these summaries is to obtain alternative opinions on the issues addressed in these summaries. All interested persons are invited to submit written comments addressing these summaries or any other matter discussed at the workshops. While we are not providing a deadline for the submission of comments, and in effect are eliminating the November 5, 2001 deadline given in the October 5, 2001 notice, the comments should be submitted as soon as reasonably possible.

Comments related to this proceeding may be filed in paper format or electronically. Those filing electronically do not need to make a paper filing.

For paper filings, the original and 14 copies of the comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington D.C. 20426 and should refer to Docket No. RM01-12-000.

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[1] The attachment is not being published in the Federal Register.

To file the comments in an electronic format, access the Commission's website at www.ferc.gov, click on "e-Filing" and then follow the instructions for each screen. First time users will have to establish a user name and password. The Commission will send an automatic acknowledgment to the sender's E-mail address upon receipt of comments. User assistance for electronic filing is available at 202-208-0258 or by E-mail to efiling@ferc.fed.us. Comments should not be submitted to the E-mail address.

All comments will be placed in the Commission's public files and will be available for inspection in the Commission's Public Reference Room at 888 First Street, N.E., Washington D.C. 20426, during regular business hours. Additionally, all comments may be viewed, printed, or downloaded remotely via the Internet through FERC's homepage using the RIMS link. User assistance for RIMS is available at 202-208-2222, or by E-mail to rimsmaster@ferc.fed.us. The comments may also be viewed by accessing the Commission's website at www.ferc.gov, clicking on "RTO Activities" and then clicking on "Electricity Market Design and Structure."

David P. Boergers
Secretary

Attachment

Electricity Market Design and Structure
Docket No. RM01-12-000
October 15-19, 2001

Staff Summary of Discussions

Monday, October 15 (AM): ***RTO Markets and Design: Required RTO Markets***

Peter Cramton, Professor, University of Maryland
The Honorable David F. Hadley, Commissioner, Indiana Utility Regulatory Commission
Mark D. Kleinginna, Corporate Energy Director, Ormet Corporation
John Meyer, Vice President of Asset Commercialization, Reliant
John L. O'Neal, President, Mirant Mid-Atlantic
Roy J. Shanker, Ph.D.

RTOs should operate a real-time energy market and ancillary service markets to procure regulation, spinning reserves, and perhaps non-spinning reserves markets. However, there was some disagreement about whether an RTO should be required to operate a day-ahead energy market. No one argued that an RTO needs to operate energy markets farther forward than day-ahead.

Some panelists noted that bilateral contracts are an essential feature of such a market and in fact only a small amount of power is traded in Northeastern spot markets. The RTO need only schedule such bilateral contracts, and let market participants choose whether to rely on bilateral contracts or spot transactions. Most participants are likely to manage risks better using bilateral markets, but they will also frequently use the spot market as a result of load variation and generator outages.

One panelist suggested that a bid-based balancing market, by itself, may not allow recovery of all legitimate fixed costs, especially in the absence of price-sensitive demand-side bids. Others noted that installed capacity markets or operating reserve markets could set prices that recover fixed costs.

The real-time energy market, the regulation market, and the operating reserves markets should have a standard market design. Standardization of these markets will reduce seams problems and increase market transparency. The markets should be based on supply and demand bids, and should establish transparent prices. The market should be designed to allow different energy prices to be established in different

locations where transmission constraints exist. (There was some disagreement about whether the locations should be individual nodes or broader collections of nodes. However, one panelist suggested that, with LMP, nodes could be aggregated to facilitate trading as in PJM.) All panelists also agreed that sellers and buyers at a given location and time should face the same energy price. However, many panelists concluded that loads should also pay for a share of ancillary service costs in proportion to their purchases. Effectively, then, the total amount paid by load per MWH of energy purchased, would be more than the total amount paid to sellers per MWH of energy produced.

Panelists agreed that it was important to allow demand-side bidding and perhaps use other mechanisms to ensure enhanced demand responsiveness. There was some disagreement about how best to encourage efficient price response from customers. One argued that customers should be paid to reduce their purchases. Another disagreed, arguing that the financial reward to customers for conservation when prices are high would be in avoiding the payment of high prices. Panelists expressed some uncertainty about how the Commission, as well as state regulators, should be involved in ensuring demand responsiveness.

RTOs should procure imbalance energy through a bid-based real-time energy market, using a security-constrained, least-cost model to dispatch the system and establish locational prices. The "security-constrained" feature of the model takes into account the various generation and transmission constraints and possible contingencies (like an unexpected outage of a generators or a transmission line).

The RTO should procure regulation and operating reserves through bid-based markets, although customers should be allowed to self-supply capacity. Several alternative suggestions were made regarding who should pay for ancillary service costs, including day-ahead customers, real-time customers, all loads, and all who deviate in real time from their forward schedules. Ancillary services (*e.g.*, commonly blackstart and reactive power) that are not competitive should be procured under cost-based contracts.

Monday, October 15 (PM): ***RTO Markets and Design: Optional RTO Markets***

Edward G. Cazalet, Chairman, Automated Power Exchange
Steven T. Naumann, Transmission Services Vice President, Commonwealth Edison
Richard J. Pierce, Jr., Lyle T. Alverson Research Professor of Law, George Washington University
The Honorable Jim Sullivan, President, Alabama Public Service Commission
Roy Thilly, President & CEO, Wisconsin Public Power, Inc.
Fiona Woolf, Head of the Electricity Group, CMS Cameron McKenna

RTOs should operate a day-ahead energy market. Most panelists agreed that a day-ahead market should be operated, but there were alternative suggestions about who should operate it. Several suggested that the RTO should operate it; a couple suggested that the RTO should (or could) contract out the day-ahead market to a for-profit independent market operator, who would have a financial incentive to operate it efficiently. One panelist noted that a day-ahead market is needed in order for load to participate effectively in the market, noting that day-ahead price signals rather than real-time price signals would generally be needed by a factory to shift production.

There was no consensus on what type of bid structure should be used. Bid structure was not discussed extensively, though one panelist voiced support for allowing three-part bidding.

RTOs should impose some type of capacity obligation on load serving entities. Ultimately, most panelists agreed that some type of long term capacity obligation is desirable, at least as long as demand is not very price responsive, in order to provide a mechanism for generation to recover sufficient fixed costs to support investment. (One, however, argued for replacing the capacity obligation with a public reporting requirement – that load serving entities publicly report their capacity holdings.) Those supporting the capacity obligation argued that until there is significant price response from demand, energy markets will not clear at politically acceptable prices during tight supply periods. However, the capacity obligation must be for a product that provides real value for customers. Some panelists supported the recent staff proposal supporting an LSE holding forward call options on energy. And there was some discussion about a capacity obligation being a transitional mechanism, and when it should be terminated, *e.g.*, when there is significant price responsiveness from demand.

Tuesday, October 16 (AM): ***Congestion Management and Transmission Rights***

The Honorable Nancy Brockway, Commissioner, New Hampshire Public Utilities Commission
Reem J. Fahey, Director of Market Policy, Edison Mission Energy
Carol Guthrie, General Manager for Electric Market Strategies, Chevron-Texaco
Shmuel Oren, Professor of Industrial Engineering and Operations Research/Director of the Power System Engineering Research Center, University of California at Berkeley
Andrew Ott, General Manager of Markets Coordination, PJM Interconnection, LLC
Michael M. Schnitzer, Director, The NorthBridge Group

The minimum requirements for congestion management should be LMP plus additional financial instruments for hedging. The panel was nearly unanimous in the view that the standard RTO market design should include locational marginal pricing as the platform for congestion management. The RTO can then easily overlay the necessary financial instruments for hedging congestion costs. However, one panelist suggested that LMP should not be required for all RTOs, because, in the West, markets and transmission systems historically have operated differently from those in the East.

Congestion costs should not be socialized. Everyone agreed that the costs of congestion should be borne by those responsible. The costs should not be socialized.

Transmission rights should be financial, not physical. All agreed that transmission rights should be financial, not physical; *e.g.*, they should entitle the holder to a revenue stream equal to the congestion costs borne by the rights holder. They should allow physical power to always flow, with congestion resulting in higher congestion prices but never curtailment.

Point-to-point firm transmission rights (FTRs) vs. flowgate rights (FGRs) can co-exist so long as transmission rights are financial. The panelists ultimately agreed that RTOs could feasibly offer market participants the choice between FTRs and FGRs, as long as both are offered as financial rights (and not physical rights). There was some disagreement (and confusion) as to the advantages and disadvantages of point to point financial rights or FTRs (*i.e.*, the right between a receipt and delivery point regardless of the physical transmission lines used), and flowgate rights or FGRs (*i.e.*, the right along a specific transmission line, known as a flowgate). Some on the panel argued that the equivalent of an FTR can be obtained by purchasing a properly designed portfolio of FGRs. However, since panelists ultimately agreed that RTOs could offer both financial

FTRs and FGRs, market participants (rather than FERC) can decide for themselves which type of right has greater advantages.

The Commission should not define what is "commercially significant." It was noted that, in an effort to achieve simplicity and liquidity, the design of some congestion management approaches rests on the assumption that, at some level, the cost of congestion is not commercially significant. The panelists generally agreed, however, that these approaches are undesirable for the real time market because they can lead to the socialization of some congestion costs and they raise the question of who decides what is commercially significant.

Both "options" and "obligations" are desirable. In their most basic form, financial transmission rights, like other hedging instruments, provide a revenue stream that can be both positive and negative. A right of this type is known as an "obligation" right. A right that allows the rights holder to decline the revenue stream when it is negative is known as an "option" right. Panelists generally agreed that both types would be desirable, but that most transmission systems would be able to accommodate fewer option rights than obligation rights. In general, the panelists seemed to prefer an approach whereby the RTO would offer at least obligation rights and offer option rights only to the extent they proved to be feasible and desired by market participants.

Financial transmission rights are fully consistent with efficient transmission planning. Some panelists emphasized the importance of transmission planning and most agreed that financial transmission rights are fully consistent with efficient transmission planning. It was noted that congestion problems often can be solved either by adding new generation or adding new transmission. One panelist suggested that RTOs could use an open season process (to include the auctioning of FTRs for new transmission capacity) to determine which solution is the efficient one.

Tuesday, October 16 (PM): ***Planning and Expansion***

Jose Delgado, President & CEO, American Transmission Company
The Honorable Michael H. Dworkin, Chair, Vermont Public Service Board
Mark W. Maher, Senior Vice President, Transmission Business Line, Bonneville Power Administration
Laura Manz, Manager of Transmission Planning, PSE&G
Masheed Rosenqvist, Director of Transmission Strategy, National Grid
Steve Walton, Enron

A regional transmission plan with representation from all stakeholders is the best way to perform transmission planning and expansion.

Market-driven solutions are best. Several panelists suggested that RTO should encourage market-driven solutions by making price information related to congestion available so that alternative solutions (generation including renewable resources, transmission, demand-side management) can be evaluated and a least-cost/most efficient solution can be adopted. The most useful information the RTO should provide is a meaningful price signal and the locations where expansion would most effectively relieve congestion. However, one panelist argued that eminent domain issue would pose significant challenges to any market driven solution. Nevertheless, the panelists seem to agree that an RTO must have the ultimate decision making authority regarding expansion. An open question, however, is whether ultimate decision making authority means authority to compel construction either by others or by the RTO itself. There was a consensus that we would need a regulatory backstop to settle issues related to transmission expansion and planning.

Although there is agreement that locational pricing information is necessary to provide useful information regarding expansion needs, some parties particularly those from the western United States do not agree that a congestion management model using LMP is well suited for application in the West. Difficulties in applying an LMP model in the West were attributed to the configuration of the transmission grid, with long distances between generation and load, and the significant amount of hydroelectric resources in the region.

One panelist suggested that the structure of the industry needs to settle first before we would see much transmission expansion. Several panelists indicated that an independent for-profit transmission company will have the right incentives to invest in congestion-relieving infrastructure.

A clear definition of property rights is needed. At present, the longest period of transmission rights is five years in NYISO and one year in CAISO. One panelist suggested that the transmission rights should be for 15 years while others suggested it should be for the life of the facilities. A clear definition of property rights would most likely attract more participation from merchant transmission projects and result in expansion of the transmission grid and ultimately reduce congestion.

RTOs should remain neutral in selecting whether an expansion plan consists of building a new transmission line or generation. An RTO should not push for any specific solution otherwise it would lose credibility. To ensure credibility, RTOs must demonstrate: (1) lack of bias, (2) technical competence, and (3) accountability. The independence alone as envisioned in Order No. 2000 would not ensure credibility in the RTO process.

Cost analyses should consider long-term implications. Panelists agreed that we should not lose sight of the long-term. What may be less expensive in the short-term may not be ultimately a cheaper solution in the long-run. Some utilities in the past erected towers for two sets of transmission lines, although they initially installed only one set of conductors. Thus, when an RTO builds, how big should it build? The answer depends on the RTO's time horizon for transmission expansion. According to one panelist, when transmission expansions (such as AEP's 765 KV lines) were carried out in the past, it was done on a large scale predominantly to provide access to markets for nuclear generation.

Technical innovation should be taken into account when considering expansion. Technical innovations such as Flexible AC Transmission (FACT) devices can be used to extract more capability from the existing transmission lines and therefore they should be considered.

Wednesday, October 17 (AM): ***Standardizing RTO Tariffs***

Ricky Bittle, Vice President, Planning Rates and Dispatching, Arkansas Electric Cooperative Corporation
Jim Caldwell, Policy Director, American Wind Energy Association
Peter Esposito, Senior Vice President & Regulatory Counsel, Dynegy
The Honorable Rory McMinn, Commissioner, New Mexico Public Regulation Commission
Glenn B. Ross, Director of Transmission Policy, Dominion Resources
Audrey Zibelman, Vice President Transmission, XCEL Energy

All load should be placed under the RTO tariff. Nearly all panel members agreed that all load, including existing contracts and bundled retail should be placed under the tariff. Only NM Commissioner McMinn expressed reservations about this due to jurisdictional concerns. Some concern was expressed as to what the one tariff should be–the RTO tariff should not remove the benefits of existing agreements, but should build them into the tariff for all customers.

To the extent CBM exists in the RTO world to meet reliability needs of the load, it should be explicitly purchased as a service under the RTO tariff. Panel members agreed that it should and should be paid for by the load receiving benefits from CBM.

ATC should be calculated by an independent entity, *e.g.* the RTO itself. For the most part, panel members agreed that the RTO should do so. Additional comments focused on how the calculation should be made–should it be based on a standard, one size fits all formula, and should it be done first by the transmission owner and reviewed by the RTO, or should the RTO alone perform the calculation. One panelist suggested that flexibility should be built in to allow an independent transmission company to calculate this itself under the oversight of the RTO. Another was concerned about the need for a transition for turning over control of hourly ATC calculations to the RTO and wanted a procedure for the transmission owner to work with the RTO to get the ATC number right.

A new, very flexible service other than the individual company <u>pro</u> <u>forma</u> tariff's point-to-point and network services should be created as a baseline above which RTOs can offer a better service. All panel members agreed that the Commission should require some kind of new service which incorporates the maximum flexibility not present independently in each of the current network and point-to-point services. This should be a baseline service, and RTOs should have the ability to add additional services. There was much discussion on building the electric markets based

on the gas Order Nos. 436/636 model, where the Commission placed all customers on the same tariff; required that pipelines do nothing to inhibit market centers, which led to pooling and title transfers; set up a system which permitted liquid trading of transmission capacity rights; and required separation of control of the grid from the merchant function. For the electric utilities, the Commission should satisfy states by ensuring that native load customers receive sufficient transmission capacity, perhaps through an auction with the current holders having a ROFR.

There was some discussion on giving the load the transmission rights, so it can choose the resource and have access to it. In addition, parties noted the need for flexibility to design their own rates to allow them to maximize throughput, *e.g.* existing reservation/commodity rates gives pipelines the incentive to aggressively discount to beat throughput projections and, therefore, increase profits. As currently designed, load ratio share rates offer no incentives, and discounts are often taken away by the states.

A point was also made that the tariff should result in predictable and reliable transmission, maximize throughput, allow the transmission owner to attract capital, and make it easy to do business with the transmission provider. It was noted that such a new service would at least in part address the Entergy sink/source problem by allowing sellers greater freedom to change delivery points to reach load.

To get to that new service, we should lay out specific, detailed principles and require each RTO to return with a tariff that meets or beats those principles, rather than drafting specific amendments to update the <u>pro</u> <u>forma</u> tariff for RTO use. Panel members agreed that the Commission should lay out principles and require each RTO to produce a tariff by a *date certain* (six months to a year) that meets or beats those principles. The principles should include specific, measurable goals for timing, liquidity, etc., plus standard "GISB" like elements including reservation, scheduling, confirmation, and request processing standards; terminology; notice periods for maintenance; responsibility and liability; bus names; ramping protocols; and ATC calculations, assumptions, and posting times.

Wednesday, October 17 (PM): ***Cost Recovery Issues***

Craig Baker, Senior Vice President of Regulation and Public Policy, AEP Services Corporation
Susan Kelly, Principal, Miller, Balis & O'Neil
William K. Newman, Senior Vice President, Transmission Planning & Operations, The Southern Company
Steve Ward, Public Advocate, Maine Consumer Counsel
Matthew Wright, Senior Vice President, Pacificorp
The Honorable James M. Irvin, Commissioner, Arizona Corporation Commission

License plate rates may be necessary for a while. There was general recognition that license plate rates may be politically necessary but some panelists felt they should be used only for a short transition period; the length of the transition period could be determined by determining the impact of cost shifting. Moreover, some panelists felt that license plate rates alone would not send appropriate price signals; rather, a new rate form may be needed to send appropriate signals; one panelist acknowledged that postage stamp rates send no price signals.

No consensus for cost recovery. Regarding cost recovery for existing facilities, no real consensus emerged; some proposals included (1) allowing cost recovery on an accelerated basis; (2) allowing a higher rate of return; (3) recovery of remaining costs only under formula rates; and (4) more Federal/state collaboration on cost treatment in the respective jurisdictions.

New flexible approaches to expansion should be encouraged. Regarding expansion of facilities, there was general consensus that the Commission should permit, and respond more quickly to, new and flexible approaches to encourage expansion. There was general opposition to use of eminent domain to accomplish this. The panelists expressed mixed views about incentive rates although most agreed that the Commission should be careful about the incentives offered. The panelists expressed concern about uneconomic investment in generation and generally agreed on the need to send the proper price signals.

A collaborative process is needed to address cost shifts. In addressing Federal and state jurisdictional interests, the panelists generally supported more collaboration to address such matters as cost shifting and siting of facilities. However, one panelist felt that the states were the best judge regarding siting and expressed concern about states' jurisdictional authority to transfer any of their pricing authority. There was general consensus that one glove does not fit all, *i.e.*, regional differences should be considered.

Panelists were generally receptive to placing all load under the RTO tariff as long as rates under existing agreements were not changed.

No consensus on classifying facilities. Panelists were split on whether to classify based on the seven-factor test or on usage. Moreover, concern was expressed that controlling lower voltage facilities would be too difficult for the RTO.

Thursday, October 18 (AM): ***Meeting with State Commissioners***

There were 36 panelists, including:

The Honorable Arnetta McRae, Commissioner, Delaware Public Service Commission

The Honorable William M. Nugent, Commissioner, Maine Public Utilities Commission

The Honorable Rory McMinn, Commissioner, New Mexico Public Regulation Commission

The Honorable Catherine I. Riley, Chairman, Maryland Public Service Commission

The Honorable Glen Thomas, Chairman, Pennsylvania Public Utility Commission

The meeting with the state commissioners consisted mostly of statements by individual commissioners. There was not an attempt to reach consensus among all presenters on the issues. The states were in agreement, however, in calling for a means of working with the FERC on RTO issues.

States' Role in RTO Formation and Market Oversight Processes: To address RTO formation and market oversight processes, state commissioners called on the FERC to establish a means for collaborating with the FERC on these issues. For example, some said FERC should initiate either a Section 209(a) joint board or an advisory panel composed of states. Others suggested that the Commission could conduct a series of workshops around the country to address these issues. They asked the FERC to set a realistic time table for state participation, taking into account that the states may have their own scheduling and legal restrictions on immediate participation.

Costs and Benefits of RTOs: Many state commissioners called on the FERC to do a cost-benefit analysis for each RTO region (and perhaps for each state) to determine the effect on retail customers, based on an evidentiary record. States that called for such analysis include especially (1) states with low cost power, which are concerned that the RTO will establish a large market that cause local retail rates to increase, and (2) states that are concerned that a large RTO may adopt a market design that will not work well for the local area. Other states said that an existing ISO has already lowered retail customer rates.

Pace of RTO Formation: States differed on the pace FERC should follow on RTO formation. In general, states in most parts of the country want a more deliberate process of RTO formation with improved state input. However, some added that the FERC process should not delay efforts by existing ISOs to fix markets problems now.

The Midwestern states, while supporting improved federal-state collaboration, called on the Commission to act quickly to establish a large RTO for the Midwest.

RTO and Market Rules: Some state commissioners expressed concern that reliance on consensus solutions among market participants would not necessarily lead to the best solution for the retail customer. Some states asked the Commission not to prescribe generic RTO rules that may be inappropriate for some regions.

Thursday, October 18 (PM): ***Standardizing Markets, Business and Other Practices***

Sarah Barpoulis, Senior Vice President, PG&E National Energy Group
William Boswell, Chairman, Board of Directors, GISB
David Christiano, Manager Electric System Control, City Utilities of Springfield, Missouri
David N. Cook, General Counsel, NERC
Michael Kormos, General Manager of System Operations, PJM Interconnection, LLC
The Honorable LeRoy Koppendrayer, Commissioner, Minnesota Public Utilities Commission
Marty Mennes, VP, Transmission, Operations and Planning, Florida Power & Light Company

The Commission should first decide how many RTOS there should be. There was general consensus that the Commission must decide on how many RTOs there will be before business practice standards are developed.

The Commission should first establish the basic market design. There was general consensus that the Commission needs to make policy decisions about the standardization of basic market design issues before business practice standards are developed. One panel member suggested that the Commission specifically address: congestion management, transmission service, loop flows, grandfathered transmission service, energy imbalance markets, ancillary services, losses, and the participation of non-jurisdictional entities.

The Commission decisions will have to be fairly specific to ensure the development of a uniform set of business practices. For example, just saying that the congestion management will be LMP will not work. NYISO and PJM both use LMP and there are still a lot of seams issues. FERC should issue a very specific standard market design proposal. If FERC issues a rule with this type of specificity, the industry can develop standard business practices in a matter of months.

There needs to be an organization to set industry standards. Both the Energy Industry Standards Board (EISB) and the North American Electric Reliability Council (NERC) are willing to set the business practice standards that will be needed. There was general agreement that before the standards setting process can proceed, the industry must settle on one standards setting body. There was also general agreement that reliability and business practice standards cannot be totally separated. However, there was no agreement that they must be set by the same organization. One panel member stated the belief that because the gas and electric industries are converging, standards for

both industries should be set by the same body. There was interest expressed in having FERC help speed the decision by conferences/discussions that would make industry participants commit to one process or the other.

Friday, October 19 (AM): ***Market Monitoring***

Charles J. Cicchetti, Miller Chair in Government, Business and the Economy, University of Southern California
The Honorable Robert Nelson, Commissioner, Michigan Public Service Commission
Marji Philips, Exelon Power Team
Sonny Popowsky, The Consumer Advocate, Pennsylvania Office of Consumer Advocate
Craig R. Roach, Principal, Boston Pacific Company
Anjali Sheffrin, Director, Market Analysis, California ISO

Independence of market monitoring units: Participants agreed that a market monitoring unit (MMU) should be independent from the RTO in whose region it monitors market activity and that MMUs are critical to the success of the market. They will give confidence to all market participants.

Information access and sharing: MMUs should have real time physical proximity to RTO operations. They will need discretion to investigate inappropriate market activity, including oversight of daily operations to determine if collusive or other illicit market activity results in higher prices. MMUs should also diagnose if there are structural defects in the market design and operation and propose structural improvements. MMUs could also predict future conditions such as supply and demand, and plant maintenance, and perform an early warning system to the RTOs. MMUs should be able to share information directly and freely with the Commission (as well as with State Commissions and, as appropriate, the Department of Justice). There should be no ex parte barrier to communicating with appropriate Commission staff.

Definition of actionable conduct: Panelists discussed whether gaming that did not involve the violation of any rules constituted behavior subject to sanction. Participants also did not agree whether the standard for bad behavior should be whether an antitrust violation occurred, whether there were "just and reasonable" prices, or some other standard. It was also agreed that, while MMUs need access to bilateral markets to understand how that pricing behavior relates to the spot and day ahead markets, it is not the role of an MMU to monitor and police bi-lateral markets.

Scope of MMUs remedies: Participants agreed that if the problem identified by the MMU is structural, the MMU should report its findings to the RTO and the Commission and should propose a solution. If a problem lies with one or more market participants, the MMU could reach a settlement with the market participant or refer the matter to FERC for the imposition of a remedy after due process. The panel did not

agree on whether the MMU should impose a penalty directly on a bad market actor or merely forward its findings to the Commission for action. Nor did they agree on the juncture at which proceedings involving the behavior of market participants should be made public. Most also thought that MMUs should perform an audit function of the RTO itself.

Possible formation of a working group: There was agreement that a group consisting of state and federal regulators and market monitors could be convened to develop a description of the information that a MMU should receive, and be authorized to receive, from market participants. The group should also help determine what information should be received in a standardized form by each RTO's MMU.

Friday, October 19 (PM): ***Mitigation of Market Power***

Richard Cowart, Director, The Regulatory Assistance Project
Bill Hall, Senior Vice President, Corporate Energy Policy, Duke Energy
The Honorable Edward A. Garvey, Commissioner, Minnesota Public Utilities Commission
William W. Hogan, Professor of Public Policy and Administration, John F. Kennedy School of Government, Harvard University
Paul L. Joskow, Professor of Economics & Director, MIT Center for Energy and Environmental Policy Research
Robert R. Nordhaus, Member, Van Ness Feldman, P.C.
David Patton, President, Potomac Economics

Market structure, design, and demand side management are critical. There is a need to get the structure and design right first, otherwise mitigation will be ineffective. Panelists generally agreed on the importance of demand response as a means of reducing the need for market mitigation. Bid-based, security constrained dispatch was presented as the design of choice by several panelists, with no dissenting opinions expressed.

There is a need for continued mitigation procedures. There was a consensus that even in a workably competitive market with the best design, there would still be a need for market power mitigation. Some generating units would be likely to require mitigation indefinitely.

The Commission must work with states. This point was general, but discussion focused on the need to work with states to encourage demand response and remove barriers to demand participation (through real-time metering, or other means.)

Independence of the market monitor's mitigation actions. There seemed to be general agreement that mitigation should be independent, in the sense of a market monitoring unit being able to report all its findings directly to the Commission without first being required to submit them to the RTO committees or the RTO board. It wasn't clear whether this required the market monitor/mitigator to have its own independent board.

Before the fact mitigation is better. Panelists were generally very reluctant to intervene after the fact to alter market outcomes, particularly long after the fact, although most seemed to feel that after the fact intervention would sometimes be necessary. One of the panelists said that while this is true, the presence of a big club for ex-post mitigation can act as a deterrent.

Rule violations should be publicly disclosed. Disclosure served the purpose of a deterrent. However, there was not agreement on exactly when violations should be made public. Although all agreed that violations should be made public once a final determination had been made, some had due process concerns about any earlier disclosure.

Bid caps should be limited. While bid caps were viewed as undesirable, high bid caps or other price mitigation was viewed as necessary when demand unresponsive and supply was limiting. A desirable mitigation procedure would limit distortion of market outcomes and should designed so that it would no longer be limiting when demand response or entry occurred. Some concern was expressed that mitigation procedures would need to be explicitly terminated.